Virtual Regional Transmission Organizations And the Standard Market Design

A Conceptual Development with Illustrative Examples

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ABSTRACT

In this paper, EPRI describes the technical concept of a virtual Regional Transmission Organization (vRTO) under the FERC-proposed Standard Market Design (SMD) and provides illustrative examples. It is envisioned that this paper would be used for discussion by stakeholders in the electric power industry. It should be noted that this paper applies to the Day-Ahead Market as well as the Real-Time Market even though it focuses on the security-constrained dispatch problem. By ensuring that the Day-Ahead solutions for all RTOs within an interconnection do not have congestion, the real-time operation will be greatly improved even when conditions depart from the day-ahead forecast. The objective of this paper is to explore the mathematical basis or operating conditions for two or more LMP systems in an interconnection employing Locational Marginal Pricing (LMP) to iterate between their security-constrained economic dispatches in such a way as to assure that global transmission constraints are satisfied in the mutually inclusive footprints of the common interconnection, and that the LMP prices in the constituent systems will converge to the optimal prices if there were one single LMP system for the entire interconnection.

The technical foundation for such convergence will be explored and described through illustrative examples. It will be shown that a common power system model with real-time data exchange on critical data form part of that foundation. The degree of data aggregation and modeling approximation will be discussed, recognizing the practical issues of data availability, commercial sensitivity and degree of accuracy required. Some of these real-time data exchange will improve the accuracy of the current NERC Transmission Loading Relief (TLR) method implemented on the NERC Interchange Distribution Calculator (IDC). A proposed balanced sets of Portfolios representing the results of an LMP dispatch in an RTO will replace the point-to-point NERC Electronic tags (E-tags) in that RTO as the means to share data on transactions that affect other systems' power flows. By standardizing on an interconnection-wide set of Cohesive Electrical Zones (CEZ), both point-to-point and Portfolio E-tags can co-exist within the IDC and in fact will increase the accuracy of the IDC.

Two types of convergence will be discussed – convergence to a globally feasible solution for solving inter-RTO congestion management; and convergence to the global optimal LMP market price solution.

Convergence to a globally feasible solution is illustrated by two examples. In both cases, convergence is achieved, however, the second example shows some difficulty. The conditions under which convergence may be unachievable will be explored and discussed.

Two methods of global optimal LMP market price convergence are proposed for a vRTO.

- The first is through the human market loop. In this scheme, the generators in the entire interconnection should be free to enter into any or all of the constituent markets in whole or in parts with a short enough time interval, e.g., one hour or less, so that a market loop for global convergence may be effective in bringing about a global market equilibrium. Marketers will facilitate price convergence by seeking out, in both real time and in day-ahead markets, opportunities to profit by making inter-RTO transactions.

- The second method is to permit each RTO to bid into the day-ahead and the real-time markets of the other RTOs with its available economy energy after balancing its internal market. The bids will be in the form of one or more cost curves (based on the prices bid into its internal market) with maximum MW limits from sources located at certain CEZs. An iterative process requiring real-time exchange of the bid curves can be set up whereby each RTO solves its LMP with the external bid curves and then revising its own bid curves to the other RTOs for their next iteration. An example in this paper shows that the iterative process converges to a condition close to the single LMP global solution although it cannot be proven mathematically that convergence is guaranteed.

The statistics on the interregional transfer limits in the Eastern Interconnection as computed by the EPRI Community Activity Room (CAR Painter program) for the summer months of 2002 are presented in this paper. They are indicative of the increasing degree of congestion that has troublesome implications of worsening reliability problems, without new transmission investment coming online soon. Under these conditions, market reaction to LMP prices when heavy congestion occurs in the interconnection may not take place fast enough for the grid to avoid severe reliability problems. Such conditions may occur frequently during the summer peaks and there would be a need for an administrative reliability procedure similar to today's Transmission Loading Relief process using the IDC (Interchange Distribution Calculator) as a reliability back stop for market mechanisms.

The concept of equitable sharing of energy cost savings due to market efficiency among the customers of the constituent RTOs of an interconnected wholesale power market is also explored in this paper. A method based on reconstruction of "isolated" operation of each RTO is proposed. This may provide a win-win system whereby market efficiency due to free-flowing economic out of market sales can be achieved while the savings due to these economy sales are distributed equitable to all customers, so that all customers in all regions come out winners.

Finally, the current deficiency of SMD which does not provide financial incentive for building new transmission lines is addressed by the proposed Automatic Transmission Toll Collection (ATTC) System. The concept is based on assigning transmission toll charges based on actual usages of specific lines due to all market participants. The ATTC system provides a credible method for assessing transmission tolls that is based on sound economic and engineering principles. It is also a means for implementing Performance Based Rate (PBR) on specific AC transmission lines. It does require the implementation of an on-line computerized reconstruction and settlement system. If the sharing of market savings is implemented in a Virtual RTO, the reconstruction and settlement system needed there can be easily extended to accommodate also the ATTC system.

In summary, this paper is proposing several innovative concepts for solving some of the difficult unsolved problems arising from implementing the LMP on an interconnection.

CONTENTS

1
BACKGROUND AND INTRODUCTION

FERC NOPR on Standard Market Design

The U.S. Federal Energy Regulatory Commission (FERC) issued a Notice on Proposed Rulemaking (NOPR) in August 2002, Docket No. RM01-12-0000, "Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design." It is known in short as the NOPR on Standard Market Design (SMD). This is the third of a series of initiatives to transform and restructure the electric power industry, following Order No. 888 in 1996 and Order No. 2000 in 1999.

FERC said, as quoted from the NOPR, "We expect that most if not all entities will become members of RTOs and that the new Network Access Service would be provided through these RTOs. However, this rule may become effective at a time when some transmission owners and operators have not yet become members of functioning RTOs. Thus, we propose that all transmission owners and operators that have not yet joined an RTO must contract with an independent entity to operate their transmission facilities. This proposed rule refers to both the RTO and those independent entities as "Independent Transmission Providers" (ITP)."

Within the SMD is the proposed transmission congestion method called Locational Marginal Pricing (LMP), which is mathematically known as security-constrained unit commitment and economic dispatch. This method has been used by PJM and NYISO with success. How it would work when its electrical network does not comprise an entire interconnection is not entirely answered, theoretically and practically. When transmission bottlenecks in adjacent RTOs are affected by dispatches in an RTO, and vice versa, the inter-RTO coordination for congestion management has not been addressed in the SMD. Having one RTO for one interconnection may be the mathematical ideal solution, but there are many impediments against it.

The realities of the evolution of ISOs, RTOs and ITPs are such that it is unlikely that the near-term footprint of an RTO would in all cases encompass an entire interconnection. (The North American electricity grid consists of three interconnections, the Eastern Interconnection, the Western Interconnection and the Texas Interconnection.) Realistically, the Eastern Interconnection and the Western Interconnection would likely have three or more RTOs or ITPs. Therefore, it is important that a practical method of inter-RTO congestion management is found which works well within the framework of the SMD, i.e., the LMP methodology.

Objectives of Paper

Tennessee Valley Authority (TVA), a non-jurisdictional Federal entity located at the fulcrum of the Eastern Interconnection, has been affected significantly by unscheduled parallel flows in the Eastern Interconnection since the dawning of transmission open access. While TVA is not legally required by FERC to comply with the SMD, it will be surrounded by RTOs which will implement LMP. This paper is funded by TVA in an EPRI tailored collaboration project to investigate a practical method for inter-RTO congestion management, within the LMP framework. It is hoped that this paper will provide timely and useful technical information for discussion by stakeholders with an interest in this subject.

Scope of Paper

This paper will describe the technical concept of a virtual Regional Transmission Organization (vRTO) under the FERC-proposed Standard Market Design (SMD) and will provide illustrative examples. This paper will explore the mathematical basis or operating conditions for two or more LMP systems in an interconnection employing Locational Marginal Pricing (LMP) to iterate between their security-constrained economic dispatches in such a way as to assure that global transmission constraints are satisfied in the mutually inclusive footprints of the common interconnection, and that the LMP prices in the constituent systems will converge to the optimal prices if there were one single LMP system for the entire interconnection.

The technical foundation for such convergence will be explored and described through illustrative examples. It will be shown that a common power system model with real-time data exchange on critical data form part of that foundation. The degree of data aggregation and modeling approximation will be discussed, recognizing the practical issues of data availability, commercial sensitivity and degree of accuracy required. Other conditions for LMP optimal price convergence related to the generators in the entire interconnection would be discussed, so that a market loop may bring about a global market equilibrium.

Two types of convergence will be discussed – convergence to a globally feasible solution for solving inter-RTO congestion management; and convergence to the global optimal LMP market price solution.

Convergence to a globally feasible solution is illustrated by two examples. In both cases, convergence is achieved, however, the second example shows some difficulty. The conditions under which convergence may be unachievable will be explored and discussed.

Two methods of global optimal LMP market price convergence are proposed for a vRTO.

- The first is through the human market loop. In this scheme, the generators in the entire interconnection should be free to enter into any or all of the constituent markets in whole or in parts with a short enough time interval, e.g., one hour or less, so that a market loop for global convergence may be effective in bringing about a global market equilibrium. Marketers will facilitate price convergence by seeking out, in both real time and in day-ahead markets, opportunities to profit by making inter-RTO transactions.

- The second method is to permit each RTO to bid into the day-ahead and the real-time markets of the other RTOs with its available economy energy after balancing its internal market. The bids will be in the form of one or more cost curves (based on the prices bid into its internal market) with maximum MW limits from sources located at certain CEZs. An iterative process requiring real-time exchange of the bid curves can be set up whereby each RTO solves its LMP with the external bid curves and then revising its own bid curves to the other RTOs for their next iteration. An example in this paper shows that the iterative process converges to a condition close to the single LMP global solution although it cannot be proven mathematically that convergence is guaranteed.

The conditions under which convergence may not be achievable will also be explored and discussed.

The statistics on the interregional transfer limits in the Eastern Interconnection as computed by the EPRI Community Activity Room (CAR Painter program) for the summer months of 2002 are presented in this paper. They are indicative of the increasing degree of congestion that has troublesome implications of worsening reliability problems, without new transmission investment coming online soon. Under these conditions, market reaction to LMP prices when heavy congestion occurs in the interconnection may not take place fast enough for the grid to avoid severe reliability problems. Such conditions may occur frequently during the summer peaks and there would be a need for an administrative reliability procedure (similar to today's Transmission Loading Relief process using the IDC) as a reliability back stop for market mechanisms. Alternative administrative reliability procedures will be explored and compared.

2 INCREASING CONGESTION IN EASTERN INTERCONNECTION

Summer 2002 Statistics on Eastern Interconnection Transmission Congestion

EPRI and NERC cooperated on a pre-season Eastern Interconnection study for the summer of 2002, with participation by the NERC Pre-season Security Assessment Study Team (PSAST) under the NERC Reliability Coordinator Working Group (RCWG). The funding was provided by the EPRI Transmission Reliability Initiative. An EPRI report on the study and new tools was published in June 2002. [1]

During the summer of 2002, the PSAST and EPRI performed some validation of the results of the study and the new tool called CAR™ Painter. EPRI analyzed the statistics from the EPRI/NERC TagNet Display and the CAR Painter and presented the results to the NERC RCWG in September 2002. The statistics on the transmission congestion in the Eastern Interconnection are interesting and potentially troublesome to those who are concerned about the reliability of the power grid and/or the economic efficiency of the wholesale power market.

Summary of Transmission Loading Relief (TLR) Statistics

When a Reliability Coordinator (RC) initiates a continuing series of TLR calls on the same flowgate starting from a non-zero TLR level and ending on a TLR level zero, the series of TLR calls is considered a TLR event and is required by NERC to be documented in a TLR log, posted on the NERC public website. Level 1, being a monitoring level, does not impact the market. Therefore, the number of TLR logs of Level 2 or higher, is an indicator of the degree of transmission congestion on the Eastern Interconnection.

Figure 2-1 is the chart of TLR logs as of the end of September, 2002. This chart plots the number of TLR logs for each month of the calendar years from 1997 to 2002. The degree of congestion in the summer months of May through October is quite apparent. The number of TLR logs jumped by a large amount from 1999 to 2000. The summer of 2001 saw a decrease in the number of TLRs, however, the congestion in the summer of 2002 has exceeded the summer of 2000. Figure 2-2 shows the monthly trend of the number of TLR logs. This shows a large jump in May 2000. It also shows the same year to year trend as observed in Figure 2-1. An explanation of the 2000-2002 changes in congestion is generally agreed among operators. The summer of 2000 saw record temperatures in the southern U.S. and mild temperatures in the MAPP and MAIN regions. As a result, a large amount of energy was shipped from North to South. The temperatures in the summer of 2001 were generally below the forecasts, resulting in less long-distance transfers. The summer of 2002 saw record demands in the Northeast and somewhat milder weather in the South. It also saw the commissioning of many new merchant power plants in the South, resulting in a new pattern of inter-regional wholesale power transactions, i.e., more

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South to North schedules. In recent years, no significant amount of new transmission capacities have been built in the Eastern Interconnection, as shown in Figure 2-3. It is understandable that while demands for electricity continue to grow and new power plants coming on-line, transmission congestion will increase with no new transmission capacities.

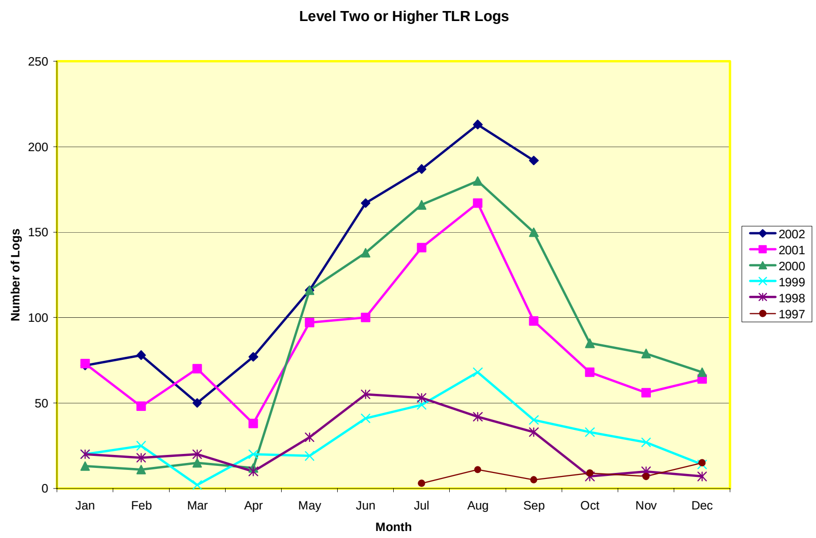


Figure 2-1 Eastern Interconnection Transmission Loading Relief Logs (Level 2 or Higher) Monthly Patterns

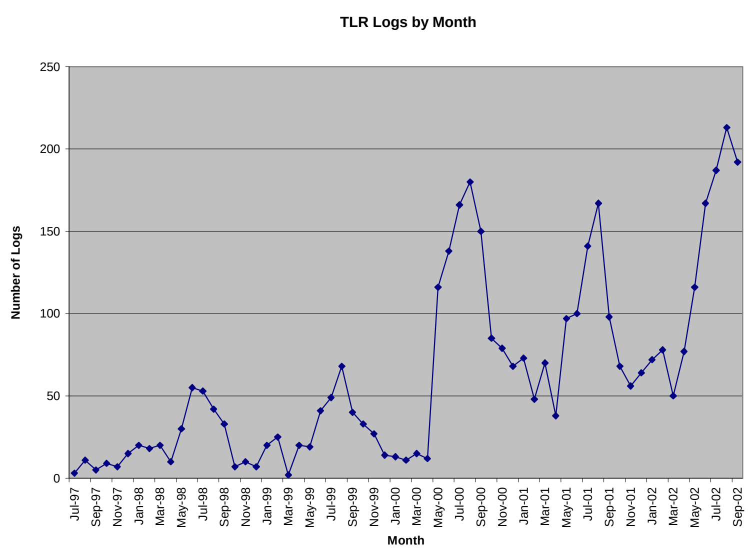
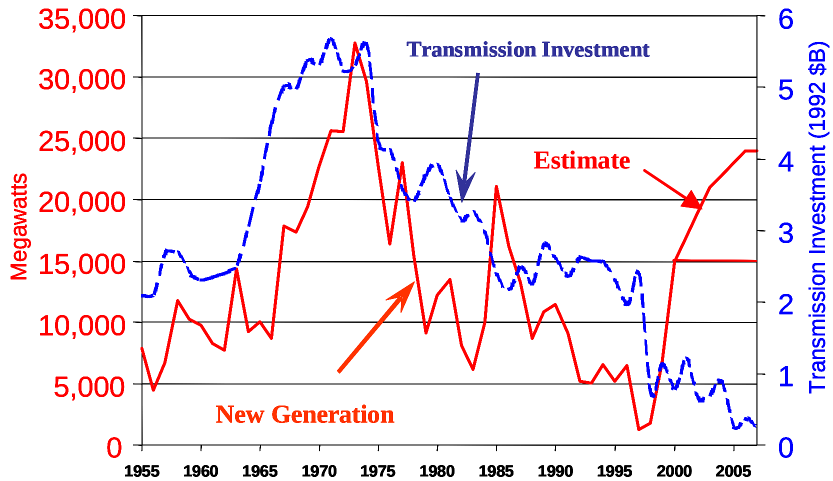


Figure 2-2 Eastern Interconnection Transmission Loading Relief Logs (Level 2 or Higher) Month-to-Month Trend



Source: Cambridge Energy Research Associates, Electric Transmission Advisory Service, 2000

Figure 2-3 U.S. Investments in New Generation and Transmission (1955-2005 Estimated)

Impact of Transmission Loading Relief (TLR) on the Wholesale Power Market

While the TLR logs give an indication of the frequency of congestion, it takes a more detailed analysis of all the TLR logs to cross-tabulate the statistics on the MW of wholesale power transactions that were cut as a result of the TLR events. This analysis was done by EPRI as part of the PSAST validation effort.

Figure 2-4 plots the amounts of transactions in MW that were cut by the various TLR levels and by the Reliability Coordinators. The latter would be a rough indication of the locations of the transmission bottlenecks.

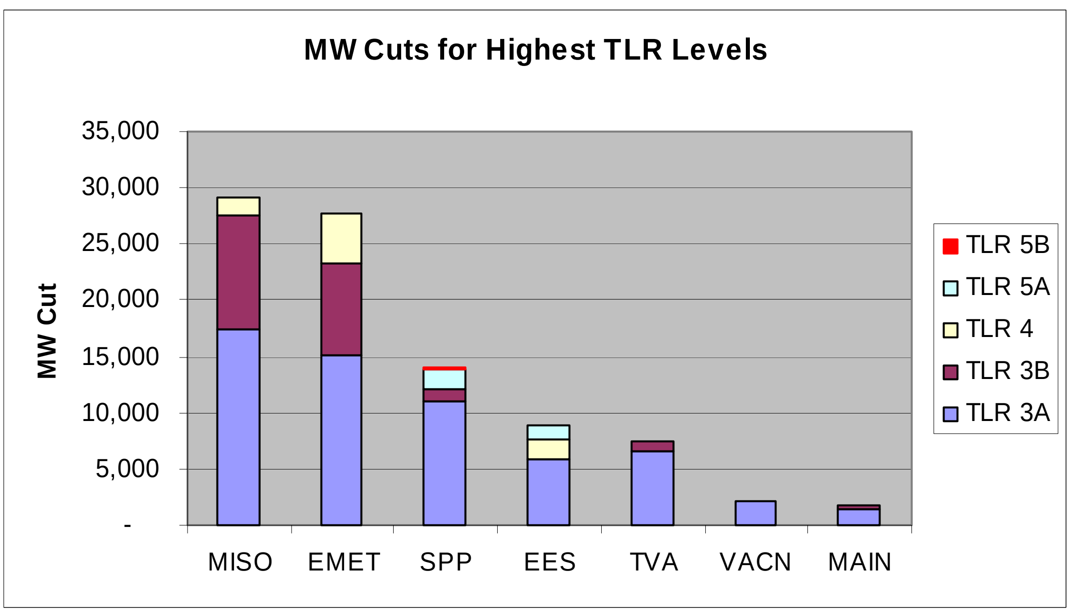


Figure 2-4 MW of Transactions Cut by TLR (May – August 2002)

The total amount of MW cut in May through August 2002 was about 91,000 MW. It should be noted that it is a relatively small percentage of the total amount of wholesale power transactions taking place in the Eastern Interconnection. For example, in a NERC report on the IDC statistics in July 2002[1], the percentage of energy cut by TLRs amounted to about 0.2% of the total amount of transactions submitted via E-tags. However, the financial impact on the market due to these 91,000 MW may not be insignificant.

An analysis of the starting hour and the mid-point hour of all TLR events with non-zero cuts was also done. Shown in Figure 2-5 and 2-6 are these charts. It can be observed that starting at 6 or 7 a.m. CST, many TLR events are initiated, and that the mid-point of most TLR events is at 2 or 3 p.m. CST. That period seems to indicate the most congested hours of the Eastern Interconnection.

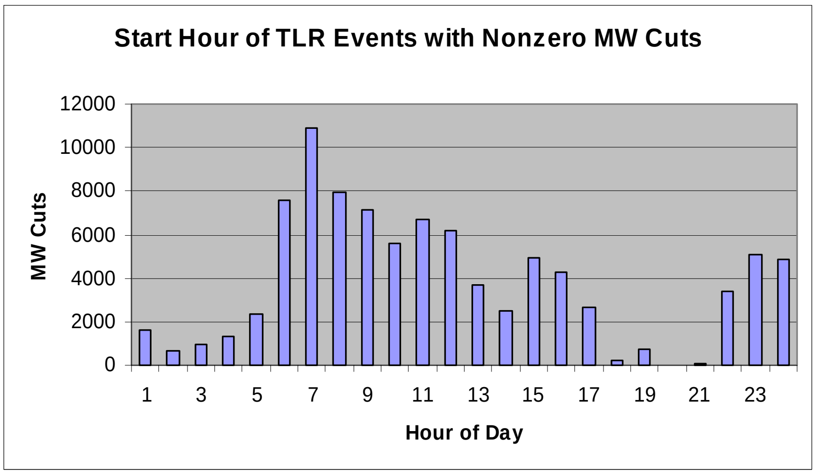


Figure 2-5 Distribution of Starting Hour of TLR with Non-zero MW Cuts (May – August 2002)

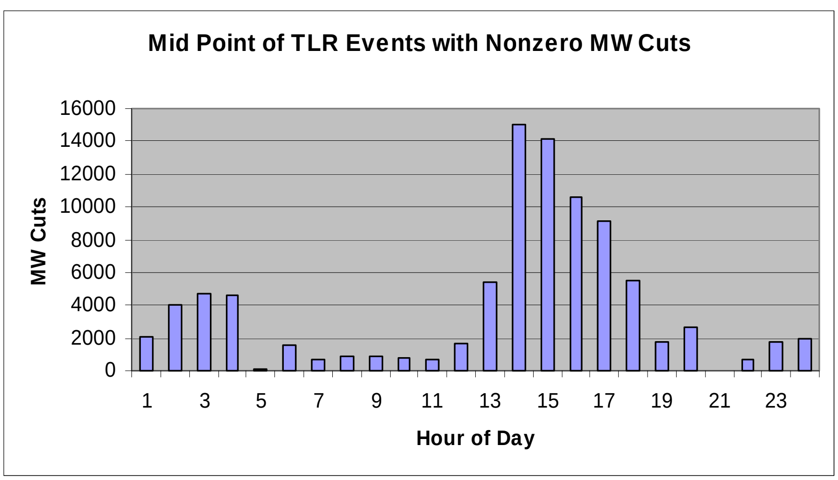


Figure 2-6 Distribution of Mid-Point of TLR with Non-zero MW Cuts (May – August 2002)

[1] NERC Market Interface Committee meeting agenda package, September 2002.

Degree of Eastern Interconnection Transmission Congestion in Summer 2002

Another analysis was done with the TLR logs whereby each TLR event with non-zero MW cuts was laid out on the time-line from the start to the end of the event and all these events are summed up for each hour of the period from June 13 through July 31, 2002. The severity of each TLR event is represented by the MW of transactions cut. As it is not known how many hours these transactions would have taken place if they had not been cut, associating the MW cuts with the entire duration of each TLR event was a reasonable way to measure the impact of transmission congestion on the market. It is one index of congestion which can be derived from analyzing the TLR logs. In this report, it is called the Total MW Cut Index.

Figure 2-7 shows the duration curve of that Total MW Cut Index from 6/13/02 to 7/31/02. Also plotted is a Congestion Index[2] for the same period as computed by the new EPRI CAR Painter program. It can be seen that the two curves generally follow the same peak shape, indicating a narrow duration for high congestion levels but a significant total duration at modest congestion, e.g., at about a Congestion Index of 100, the duration is about 300 hours (out of the 1200-hour total duration of the monitored period, or about 25%).

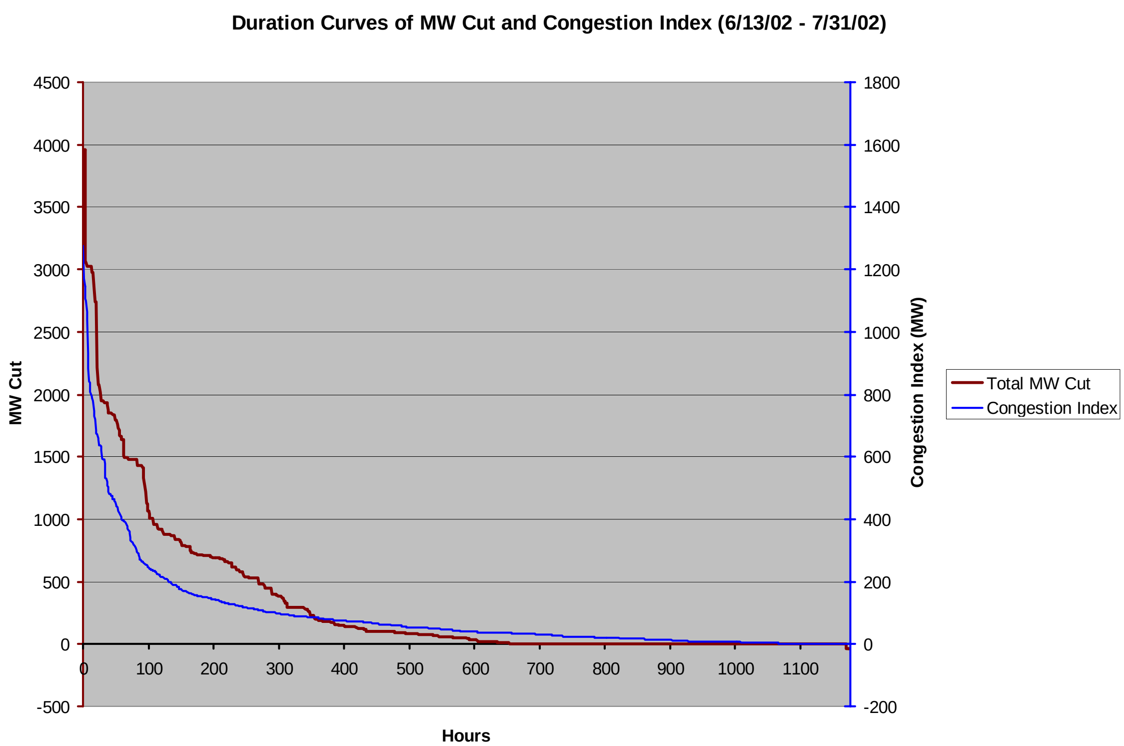


Figure 2-7 Duration Curves of Congestion Indices (6/13/02 – 7/31/02)

Appendix A is a description of the CAR Painter program.

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2 Congestion Index (CI) is defined as the sum of the potential post-contingency MW overloads on all constrained facilities and the potential post-contingency kV voltage limit violations. It is computed by the CAR Painter program based on modeled contingency-constraint pairs.

Achievable Transfer Limits of Eastern Interconnection in Summer 2002

Because the CAR Painter program represents the transfer limits in the form of equations that vary with the hourly transfer pattern, it has the data to compute the achievable maximum transfer limits for every hour. For example, if the transfer pattern is within the range of feasible reliability criteria, i.e., the Congestion Index is zero, there exists a maximum North to South transfer limit and a maximum West to East transfer limit. These are non-simultaneous limits in the sense that while N-S transfer is at its limit, it may not be possible to achieve the maximum W-E transfer at the same time. An example is show in Figure 2-8.

CAR painting of an hour with a South to North transfer pattern.

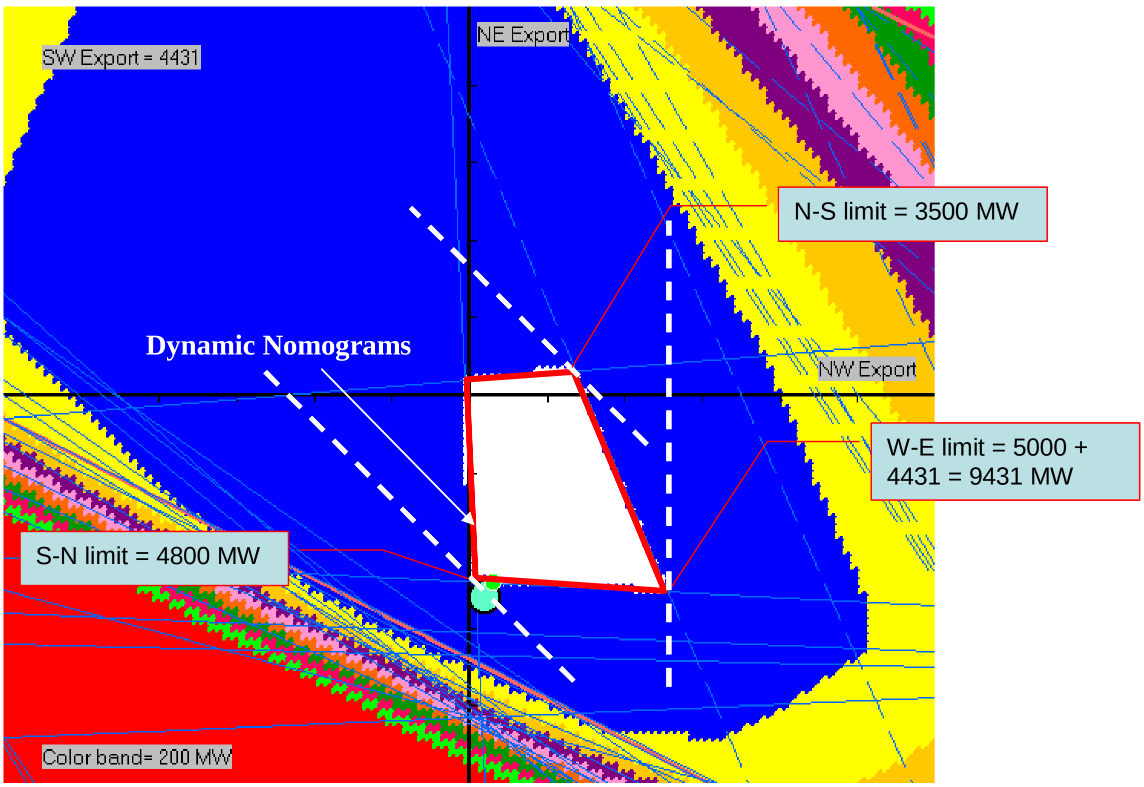

Figure 2-8 Estimation of Achievable Transfer Limits from CAR Painting

In Figure 2-8, the red four-sided shape marks the Dynamic Nomograms or the simultaneous transfer limits of the Eastern Interconnection for the depicted hour. Inside the white area, the Congestion Index (CI) is zero. The actual operating point of the hour is marked by the green disc just outside the bottom left corner of the nomograms. The Congestion Index of an operating point that lies in the blue zone is between 1 and 200, as each color band represents an incremental amount of 200 MW of potential congestion. As shown in the diagram, the export out of the SW quadrant of the Eastern Interconnection for the depicted hour is 4431 MW. The NW export is about 300 MW, and the NE export is -5200 MW. The SE export is 469 MW. (Note that the sum of the four quadrants' exports must equal zero.) The total South to North schedule is 4431 + 469 = 4900 MW. It exceeds the S-N limit of 4800 MW, as shown by the nomograms. Likewise, the N-S limit is 3500 MW and the W-E limit is 9431 MW, as shown by the related corners of the nomograms. These limits are called “achievable” transfer limits for the depicted hour.

Different achievable transfer limits can be computed for different acceptable Congestion Indices. The limits shown in Figure 2-8 are computed for an accepted CI of zero. If a depicted hour is heavily congested, there may not be a white zone of CI=0. In such cases, knowing the achievable limits for another CI would be useful. Because a CI of 100, as shown in Figure 2-7, seems to be a reasonable indication of modest congestion correlated with modest TLR cuts, it is used in CAR Painter as a alternative measure of achievable transfer limits.

The achievable North to South transfer limits during the period of 6/13/02 – 8/31/02, as computed by the CAR Painter, for three different Congestion Indices, are shown in Figure 2-9 in the form of reverse cumulative distribution curves. For example, the yellow curve corresponds to the CI level of 100. The median value of the N-S transfer limit for CI=100 is shown to be about 4300 MW. The tail end of the yellow curve, at 10% reverse cumulative level, shows that 90% of the time, the N-S achievable transfer limit is less than 6000 MW. Note that the cumulative curves on the left end show discontinuities at zero MW. For example, the yellow curve (CI=100) indicates that 75% of the time, the N-S transfer limit is greater than zero. This means that 25% of the time, the N-S transfer limit is zero. Another way of looking at this is that 25% of the time, the Congestion Index of the operation exceeded 100, and that transactions must be cut in order to avoid potential contingency overloads.

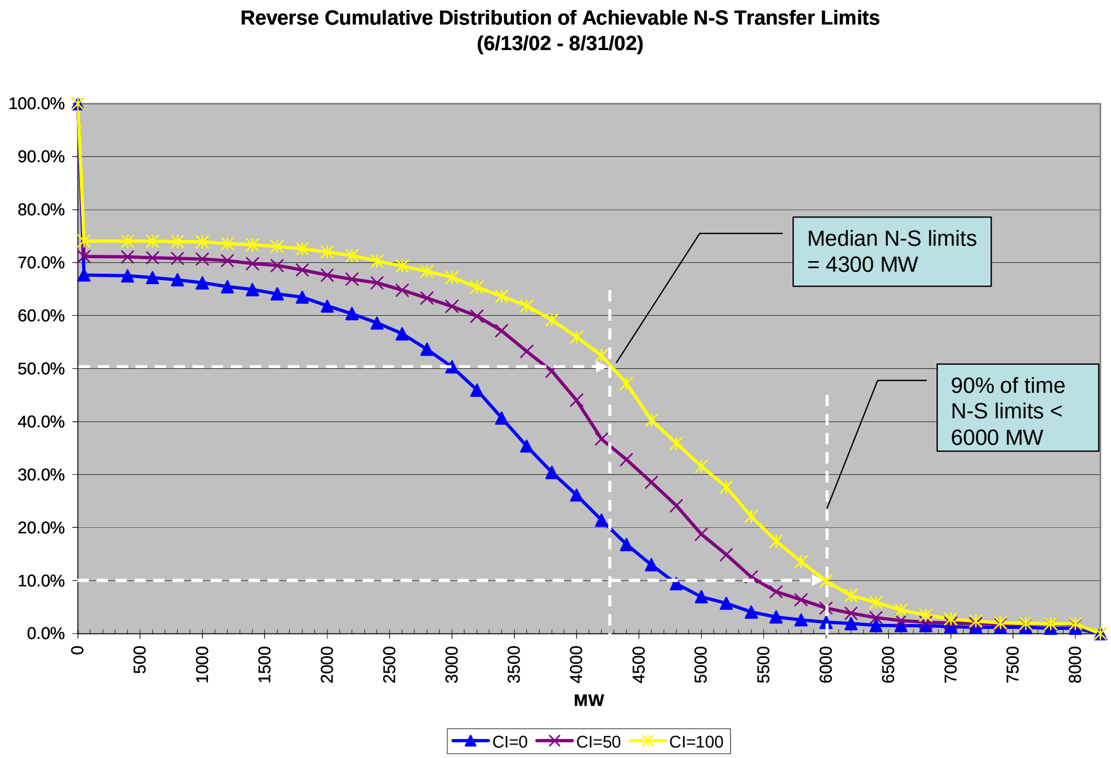

Figure 2-9 Achievable North to South Transfer Limits (6/13/02 – 8/31/02) for 3 Congestion Index Levels (CI=0, 50, 100 MW)

Similarly, the achievable West to East transfer limits during the period (6/13/02 – 8/31/02) are shown in Figure 2-10.

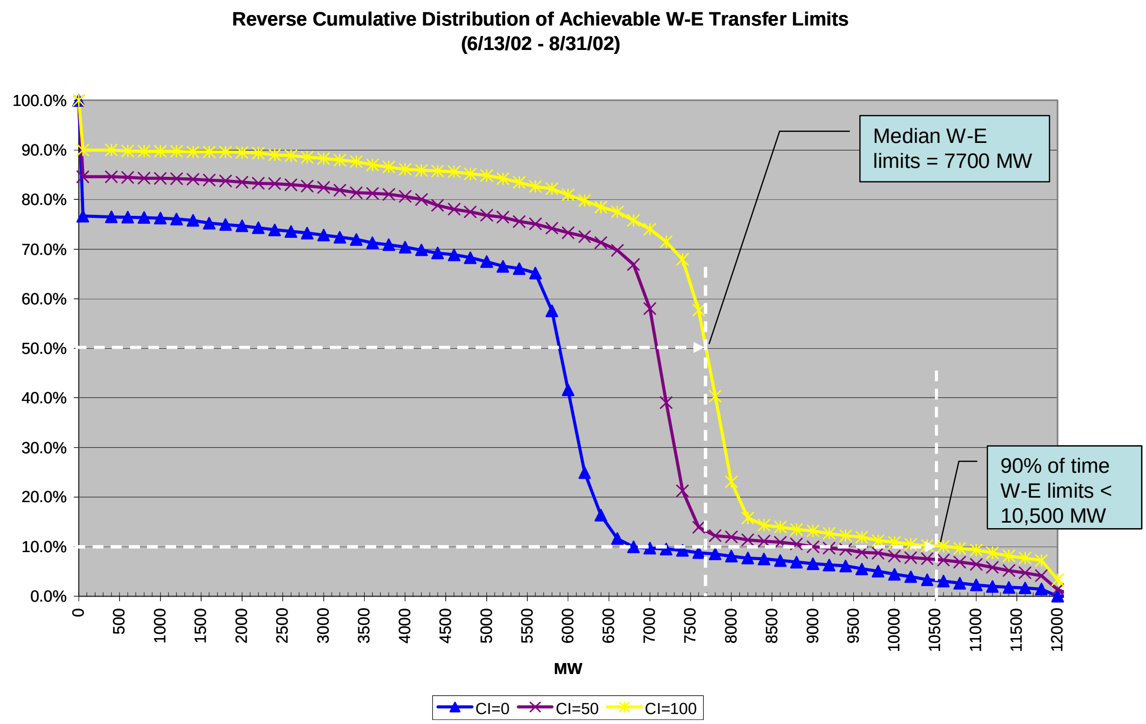

Figure 2-10 Achievable West to East Transfer Limits (6/13/02 – 8/31/02) for 3 Congestion Index Levels (CI=0, 50, 100 MW)

The results shown in Figure 2-9 and Figure 2-10 show the complex relationship between the acceptable Congestion Index and the statistical variation of the achievable transfer limits. If one demands a zero Congestion Index, the allowable transfer limits would be significantly lower than the case when one accepts a higher Congestion Index. For example, the difference between CI=0 and CI=100 in terms of N-S transfer limit is an increase from 3000 MW to 4300 MW on the average (or rather, at the median). Likewise, the median W-E transfer limit changes from 6000 MW to 7700 MW when the CI criterion changes from 0 to 100.

The implication is that within a reasonable range of acceptable potential overloads (measured by the Congestion Index), the wholesale market could see a tradeoff range of transfer limits in the order of 1300 MW in the N-S direction and about 1700 MW in the W-E direction. Accepting this tradeoff between market activities and reliability may pave the way for using probabilistic reliability indices (in a form of probabilistic congestion index) to monitor and to facilitate the tradeoff between grid reliability and the market.

Effect of Load Growth on Achievable Transfer Limits of Eastern Interconnection

The CAR Painter can be run in a reconstruction or study mode, processing all the historical hours of a study period. By projecting the daily loads of the Eastern Interconnection to 5% and 15% above the actual loads in the summer of 2002 (actually only 6/13/02 to 8/31/02 for comparison purposes), the effect of load growth on the achievable transfer limits was estimated. The assumption is also made that the transfer patterns in the Eastern Interconnection remain the same as what were observed in the summer of 2002. It is also assumed that there is no change in the transmission network. The effect of the load growth was to increase the congestion in the system because the network loads and generation take up some transmission capacity of all lines, especially the local lines many of which constitute a part of the long distance transmission path for wholesale power transactions. As a consequence, the inter-regional transfer limits are expected to diminish. Figure 2-11 shows the effect of the load growth on the duration curve of the Congestion Index.

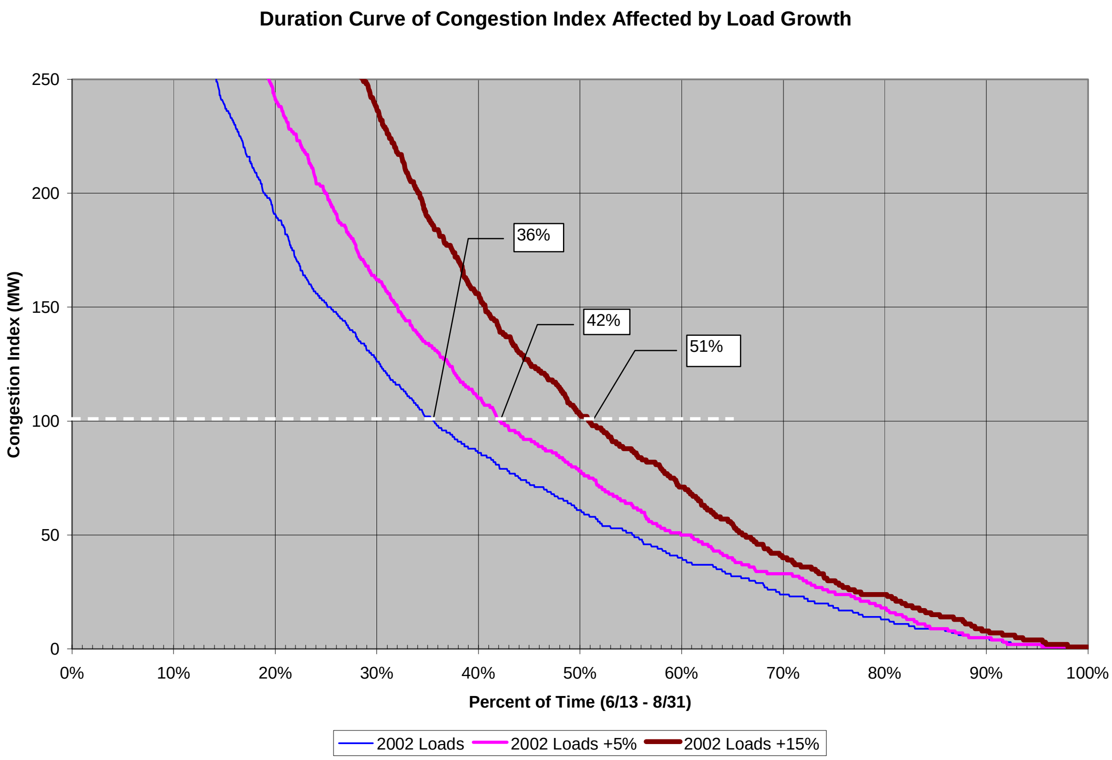

Figure 2-11 Effect of Load Growth on Congestion Index Duration Curve

In Figure 2-11, at the Congestion Index level of 100, it can be seen that acceptable congestion (at CI=100) lasts 36% of the time (6/13/02 – 8/31/02). Increasing the load by 5% would increase the duration of congestion to 42%. Increasing the load by 15% would increase the congestion duration to 51%. *This translates approximately to 15% of increased congestion duration in response to 15% of load growth.*

Another effect of load growth would be to reduce the achievable transfer limits. Figure 2-12 shows the effect of 5% and 15% load growth on the cumulative distribution curve of N-S transfer limits at the Congestion Index of CI=100.

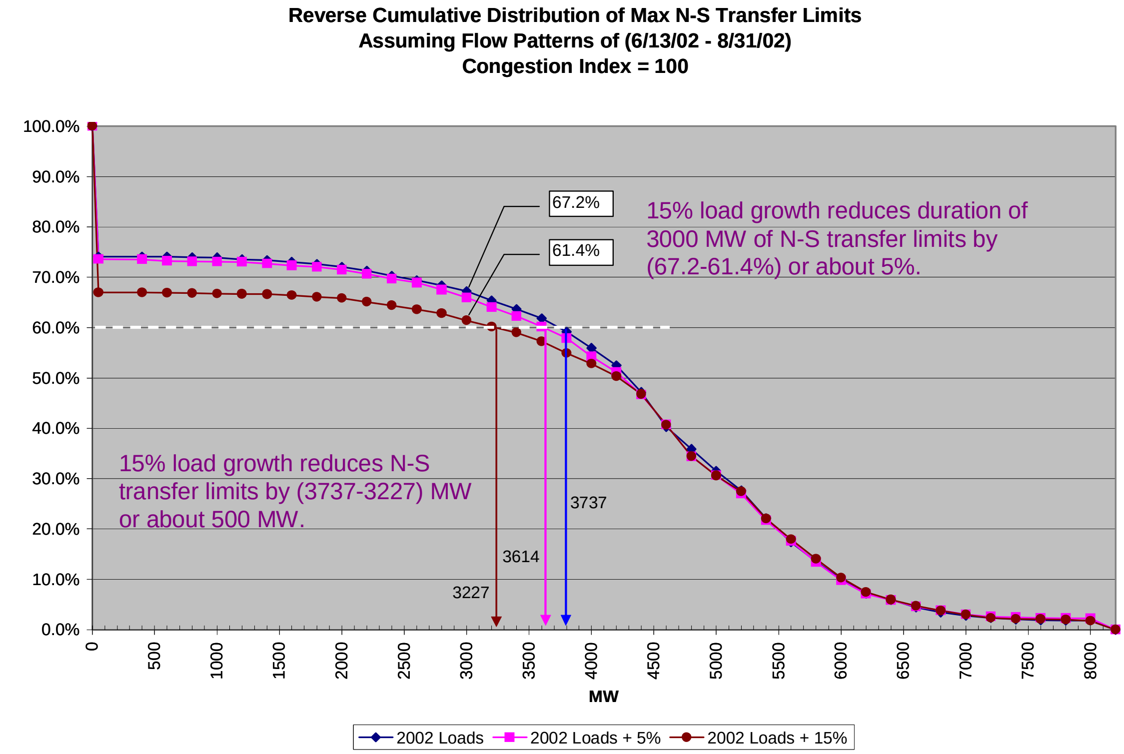

Figure 2-12 Effect of Load Growth on Achievable N-S Transfer Limits

From Figure 2-12, it can be seen that the effect of load growth is to shift the cumulative distribution of N-S transfer limits downward, in the range of transfer limits below about 4500 MW. It can be deduced that the high transfer limits are mostly achievable in the low load hours of the days when congestion is low, therefore, they are not affected by the increased loads. In the lower range of transfer limits, increased load growth would reduce the transfer limits. For example, at the same duration of 60%, the N-S transfer limit changes from 3737 MW to 3227 MW, or about 500 MW reduction, with a 15% increase in load. Another observation is that a 15% load growth reduces the duration of the achieved 3000 MW of N-S limit from 67.2% to 61.4%, or about 5%.

In summary, if one assumes that the average load growth rate is about 3% per year, a 15% load growth would happen in 5 years. In that context, the following observations can be made:

- *If there is no new transmission capacity built in the Eastern Interconnection in the next five years, the North to South transfer limits would decrease by about 500 MW.*
- *If there is no new transmission capacity built in the Eastern Interconnection in the next five years, during half of the summer period, operators will face congestion which may result in curtailments of the wholesale power market.*

From these results, although the sky is not falling, the prospect of curtailment of the market activities during half of the summer period is not comforting. It would place both grid reliability and market efficiency at risk.

More troublesome is the congestion in the South to North direction. Figure 2-13 shows the duration curve of N-S and S-N transfer at the Congestion Index of 100, for the three different load growth assumptions.

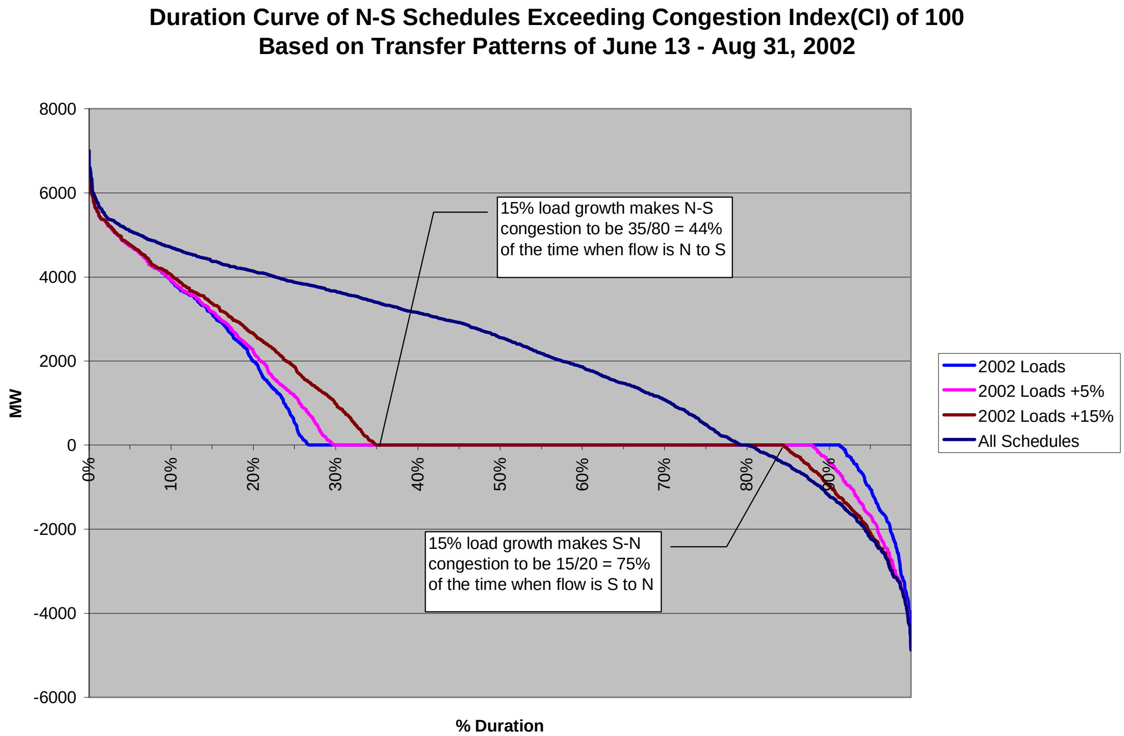

Figure 2-13 Effect of Load Growth on Duration Curves of N-S and S-N Schedules Exceeding Congestion Index of CI=100

In Figure 2-13, the actual schedules between North and South which occurred every hour in the period 6/13/02 – 8/31/02 are plotted in a duration curve labeled as All Schedules. About 80% of the schedules were in the North to South direction (as seen by positive values in the vertical axis) and about 20% of the schedules were in the South to North direction (negative values in the vertical axis.) Those hours in the study period (6/13/02 – 8/31/02) which experience a Congestion Index of 100 or higher are separated in the blue duration curve labeled 2002 Loads. Again, there is one for North to South and another one for South to North. Two other sets of these duration curves for the same CI=100 level or higher are plotted for the 5% and the 15% load growth scenarios. They show that with increasing load growth, the duration of heavily congested schedules become longer. For example, in the North to South direction, the effect of a 15% load growth is to increase the duration of heavy congestion from 26% to 35% of the entire period. Because only 80% of the entire study period involves schedules in the North to South direction, the percentage of time when heavy congestion occurs in the North to South direction would become 35% / 80% or 44%.

In the South to North direction, the effect of load growth is much more dramatic. In 2002, when the schedules are in the South to North direction, about 8%/20% or 40% of the time, there is *heavy congestion. With 15% load growth, that congestion duration would increase to 15%/20% or 75% of the time when flows are in the South to North direction.*

The conclusion from this analysis is that the South to North transfer limits will be a significant limiting factor for wholesale power transactions from the South to the North, more so than the North to South transfer limits will be limiting wholesale power transactions from North to South. This is particularly troubling because the trend in the last two years, born out by the commonly known fact that many new power plants in the South have come on line in recent months, is that power transfer in the South to North direction would increase in amounts and in duration. This is a new transfer pattern which departs from historical patterns, on which transmission plans were based. The South to North flow patterns are creating new bottlenecks which need to be alleviated quickly in order that the wholesale power market will not be unduly restricted.

Remarks

This section of the paper has presented an assessment of the degree of congestion in the Eastern Interconnection during a representative portion of the summer of 2002. It has also projected the degree of congestion if the loads in the Eastern Interconnection increase by 5% and by 15%, if no significant new transmission is built.

The general conclusion from this analysis is that congestion in the Eastern Interconnection is serious, and its impact on inter-regional wholesale power transactions will worsen with continued load growth, unless the transmission bottlenecks are reduced. It also demonstrates that the wholesale power market in the Eastern Interconnection involves the entire interconnection, and congestion management cannot be done by a single reliability entity. In the current evolutionary state of RTOs, ISOs and ITPs, it is clear that inter-RTO congestion management must be coordinated. As the congestion management framework in the Eastern Interconnection evolves to the Standard Market Design with security-constrained economic dispatch, many questions remain unanswered regarding the evolution of the Transmission Loading Relief (TLR) process currently in place in the Eastern Interconnection. Though not perfect, the TLR process, implemented with the NERC Interchange Distribution Calculator (IDC), has been providing a coordinated reliability backstop that has worked well. What will be the mechanism or form of inter-RTO congestion management in the LMP framework?

3
VIRTUAL RTO CONCEPT

What is a Virtual RTO?

FERC envisioned a Regional Transmission Organization (RTO) to operate a large transmission grid that overlays a large regional wholesale power market. FERC made its intention clear that it would like as few RTOs as possible for the entire country. Fundamental to this market and grid development direction was the premise that market efficiency would be improved by having a single large RTO overlaid on a single large regional power market, so that both reliability and market efficiency could be assured in that single power market.

Reliability in North America has always been managed well under the North American Electric Reliability Council (NERC) in concert with the regional reliability organizations. Having a single RTO in a regional power market does not intrinsically enhance reliability. Some have argued that reliability requires both big-picture oversight as well as local oversight, because of the complexity and interrelatedness of an interconnected transmission system with the underlying lower-voltage sub-transmission and distribution systems.

Since the FERC Orders 888 and 889, wholesale power market transactions had increased in both quantities and distances. In effect, each of the three interconnections (Eastern, Western and Texas) has become a single wholesale power market. Transmission bottlenecks and market rules, among other factors, are contributing to the constraints which limit the efficiency of these three markets. In effect, in order to achieve what FERC fundamentally wanted, in the original form that FERC intended, was a single RTO for each interconnection.

Therefore, the main benefit of having a single RTO for a single interconnection is to improve market efficiency. In doing so, the power industry must maintain the high degree of reliability in grid operation and manage the congestion created by more market activities, because it is well known that market activities and grid reliability are often in conflict.

This paper explores the possibility that the intended benefits of having a single RTO for an entire interconnection can be achieved by having a Virtual RTO made up of multiple grid operators (hereafter referred to as RTOs) coordinated through their control center computer systems.

A Virtual RTO is a well-coordinated group of RTOs the geographical footprints of which collectively cover an entire Interconnection. The coordination within a Virtual RTO addressed in this paper consists of data, communication, hardware and software, congestion management procedures, financial settlements and interfaces to the market. The objectives of coordination are to ensure reliability and to improve market efficiency. The specific aspect of reliability addressed by this paper is that which arise from inter-regional congestion management. The particular issue of market efficiency discussed in this paper is whether and how the human actions taken by the market in response to market signals in the entire Interconnection can achieve the effect of a single market.

In this section, the basic mathematical formulation of the Standard Market Design is discussed first. It is the security-constrained unit commitment and economic dispatch problem (in short SCD). The concept of a Virtual RTO requires that the single interconnection-wide SCD problem be decomposed into coordinated sub-problems, each for a member RTO in the entire interconnection. The coordination takes place with data exchanges. These are referred to in this paper as "Glue."

The problem of inter-RTO congestion management is then presented as finding a feasible solution of the SCD problem. With each RTO running its market while maintaining a market-wide feasible solution leaves the inter-RTO market economics to be optimized competitively by the wholesale power market. In that context, the role of the market and the human actions in response to market signals working in conjunction with the coordinated inter-RTO congestion management will be explored and discussed. It is postulated that through this market mechanism, market efficiency for the entire interconnection can be achieved. It may also be a preferred solution over an alternative, which is to let the RTOs decide how to optimize the interchanges among their markets. The latter approach would seem to potentially violate the independence principle of an RTO, with respect to market decisions.

Security Constrained Unit Commitment and Economic Dispatch

The Standard Market Design uses the Locational Marginal Pricing (LMP) methodology which is based on a security-constrained unit commitment[3] and economic dispatch[4] approach for determining the selection of day-ahead bids (through the unit commitment formulation) and the selection of hour-ahead and real-time bids (through the economic dispatch formulation, assuming that the unit commitment is already solved and fixed.)

The term security-constrained refers to reliability constraints and not cyber or physical security concerns, and has been used for such a long time in the power industry that it is kept in this paper. Typically, the security constraints refer to any potentially binding limits on the power flows, voltage limits or stability limits[5]. The limits may be steady-state limits which, if violated, would cause immediate reliability problems. They may also be post-contingency limits which, if violated, would only cause reliability problems after a critical contingency (e.g., the outage of a transmission line) happens. NERC operating criteria require that no operating limits be violated for any single contingency (often called the N-1 contingency criteria). The majority of reliability limits are contingency limits imposed on the MW flows of certain transmission lines or transformers, defined as flowgates. In the Eastern Interconnection, there are currently about 1000 reliability flowgates, many of them are related. Congestions on many of these flowgates are partially caused by parallel flows, resulting from transactions that may originate or end in control areas which are outside the impacted flowgate's control area.

[3] Unit commitment traditionally is the problem of determining the startup and shutdown sequences of all generators for the next 24 hours, up to a week. In a market operation, it replaces the generators with the day-ahead bids of capacity commitment.

[4] Economic dispatch traditionally is the problem of determining the best feasible output levels of all generators currently on-line, within their operating limits. In a market operation, it determines the real-time dispatches of the bids, within their bid limits.

[5] With today's technology, these stability limits are typically approximated by limits on aggregated line flows or net interchanges in or out of certain control areas, which can be modeled as flowgates.

For the purpose of this paper, we will limit the technical discussion to the security-constrained economic dispatch (SED) formulation. Unit commitment adds another level of mathematical complexity. If the SCD problem for a Virtual RTO does not work, the unit commitment will not work. Therefore, addressing the SCD problem is the first step.

The mathematical formulation of the security-constrained economic dispatch for an isolated power market can be represented as follows:

$$
\begin{array}{ll}
\textit{Minimize } C(\underline{x}) & Eq.1 \\
\textit{subject to}: & \\
h(\underline{x}) = 0 & Eq.2 \\
\underline{g}(x) \leq \underline{T}_{\max} & Eq.3
\end{array}
$$

Eq. 1 is the cost of electricity for the given hour as a function of the dispatched levels of all generators represented by the vector $\underline{x}$. Eq. 2 is the supply and demand balance equation that any feasible dispatch solution must satisfy. Eq. 3 are the set of inequalities representing the security constraints, where the vector $\underline{g}$ represents the steady-state or post-contingency line flows which are required to be within their respective limits specified by T_{max}.

The fundamental assumption behind this formulation is that all generators and all security constraints in the isolated power market are included. The power flow equations (Eq. 3) which model accurately the effect of parallel flows are assumed to be adequate and accurate. These assumptions are necessary in order to assure that the resulting optimal dispatch is feasible, in that all security constraints (both steady-state and post-contingency) are simultaneously satisfied.

We will now look for a more realistic formulation where several RTOs together comprise an isolated power market, or equivalently, a single interconnection. We shall first ask the question whether it is possible for a decomposed formulation to assure that a globally feasible solution can be obtained iteratively.

Decomposed Feasible Solutions

For illustrative purposes, we shall assume four example RTOs within a single interconnection with eight RTOs, called RTO A, RTO B, RTO C and RTO D. See Figure 3-1. It is assumed that each RTO communicates at a regular time interval to the other RTOs its dispatch decisions. Each RTO will ensure that its dispatch decision will satisfy all security constraints in the entire interconnection, while assuming that the dispatch decisions of the other RTOs will not change during the next time interval. The time interval of data-sharing may be in the order of 5 minutes, determined by the time interval at which each RTO's dispatch problem can be solved in real time. Synchronization of the data exchange is not mandatory, though preferable, to ensure maximum accuracy.

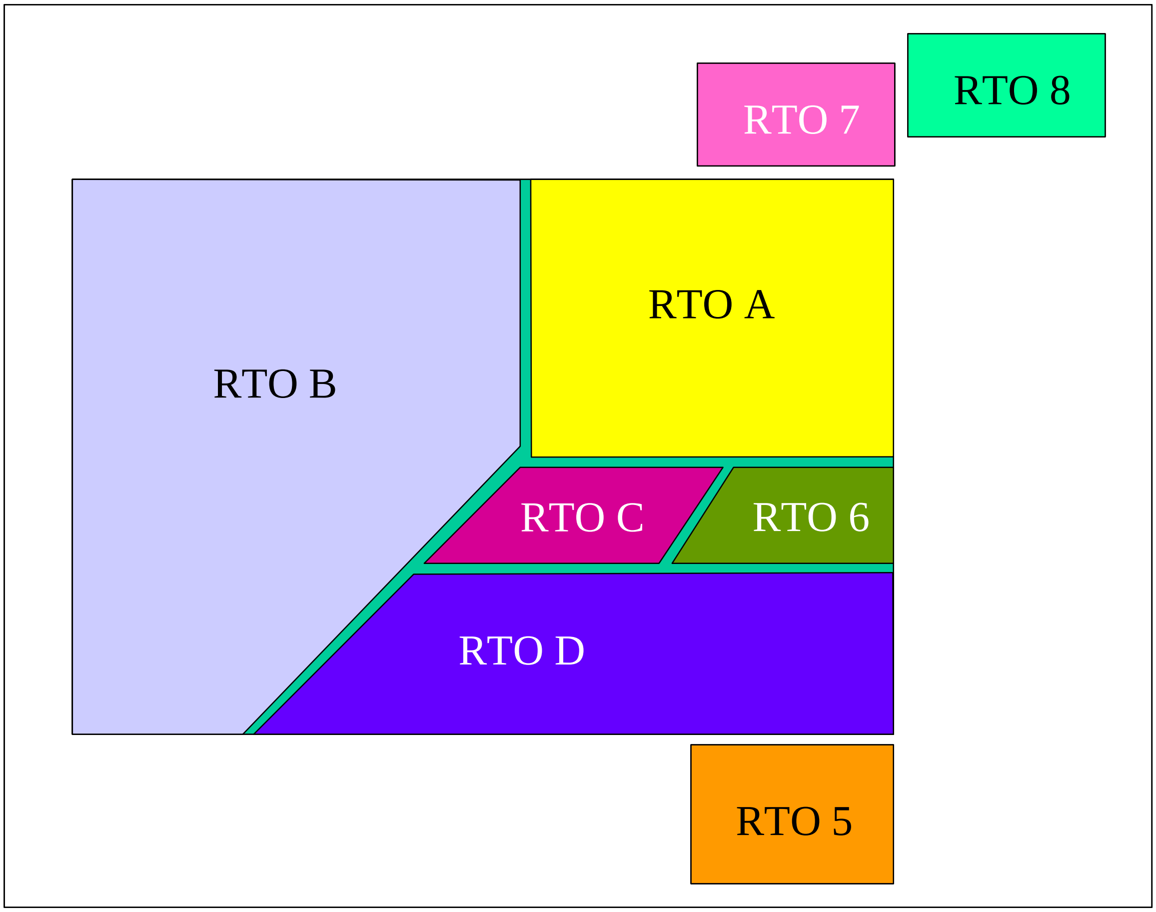

Figure 3-1 A Hypothetical Interconnection with Four Example RTOs (A, B, C, D)

For each RTO in an interconnection, e.g., RTO A, the security-constrained economic dispatch problem which respects the security constraints in the other three RTOs, with assumed constant dispatch decisions for the other three RTOs, is formulated as follows:

$$\begin{array}{ll}
Minimize\ C(\underline{x}_A) & Eq.4 \\
subject\ to: & \\
h_A(\underline{x}_A)=0 & Eq.5 \\
\underline{g}_A(\underline{x}_A,\underline{x}_B,\underline{x}_C,\underline{x}_D)\le \underline{T}_{A,\max} & Eq.6 \\
\underline{g}_B(\underline{x}_A,\underline{x}_B,\underline{x}_C,\underline{x}_D)\le \underline{T}_{B,\max} & Eq.7 \\
\underline{g}_C(\underline{x}_A,\underline{x}_B,\underline{x}_C,\underline{x}_D)\le \underline{T}_{C,\max} & Eq.8 \\
\underline{g}_D(\underline{x}_A,\underline{x}_B,\underline{x}_C,\underline{x}_D)\le \underline{T}_{D,\max} & Eq.9 \\
with & \\
\underline{x}_B,\underline{x}_C,\underline{x}_D \quad assumed\ fixed &
\end{array}$$

A few comments would be useful here. For an RTO which has transmission connection to other RTOs and where generators or marketers outside of its power market are allowed to bid into it, the decision variables $\underline{x}_A$ would include these external purchases and sales and their costs are included in Eq. 4. The energy balance equation (Eq. 5) would also recognize these external transactions. This means that Eq. 5 requires that the RTO's internal market generations and internal market loads sum up algebraically to match the net export or import with respect to the external power markets. For RTO A, reliability constraints on facilities in its system are modeled by Eq. 6. They are affected by the dispatches in the other three RTOs, i.e., $\underline{x}_B, \underline{x}_C, \underline{x}_D$. Because the dispatches in RTO A in turn affects the reliability constraints in the other RTOs, it is necessary for them to be included as constraints for determining the feasible dispatch in RTO A. These are represented by Eqs. 7, 8, and 9.

The problems for the other three RTOs can be formulated in the same way, by replacing the subscript A with B, C, and D.

It is useful to also show the global problem for the whole interconnection, as follows:

$$\begin{aligned}
&Minimize\ C(\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) && Eq.10\\
&subject\,to:\\
&h\ (\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) = 0 && Eq.11\\
&\underline{g}_A\ (\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) \le \underline{T}_{A,\max} && Eq.12\\
&\underline{g}_B\ (\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) \le \underline{T}_{B,\max} && Eq.13\\
&\underline{g}_C\ (\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) \le \underline{T}_{C,\max} && Eq.14\\
&\underline{g}_D\ (\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) \le \underline{T}_{D,\max} && Eq.15
\end{aligned}$$

From these equations, it can be shown that if a global feasible solution exists ($\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D$), it will satisfy Eq. 12-15, by definition. If it is assumed that a convergence process exists for the decomposed problems, then the global feasible solution also satisfies each sub-problem's Eq. 6-9. Eq. 5 in each sub-problem, however, may not be consistent with Eq. 11 of the global problem, because the external market transactions in each RTO may not be the same as the globally dispatched solution of Eq. 10-15. Recognizing that Eq. 6-9 and Eq. 12-15 are identical and are in fact congestion constraints, it can be concluded that *a congestion-feasible global solution is also a congestion-feasible sub-problem solution as formulated. Also, a congestion-feasible sub-problem solution as formulated is also a congestion-feasible global solution.*

We shall address the problem of convergence and optimality later in this paper.

Necessary Glue for a Virtual RTO

From the problem formulation for RTO A, shown in Eqs. 4-9, it can be seen that certain data about the other RTOs are needed in order to solve the RTO A's problem. They can be classified into three types, common power system model, common definition of cohesive zones, and real-time data.

Common Power System Model

In order for each RTO to formulate the reliability constraints, represented by Eqs. 6-9, a common power system model for the entire interconnection must be used by all of them. This is because when one RTO (e.g., RTO A) adjusts its dispatch to satisfy reliability constraints in another RTO (e.g., RTO B), the effect as modeled by Eqs. 6-9 must be reasonably accurate. Mathematically, these equations are power flow equations (either steady state or post-contingency) that accurately represent the current network status of the interconnection, i.e., line and transformer outage status. The network status data belong to the category of real-time data and will be discussed later.

There are at least three ways of ensuring consistency in each RTO's formulation of Eqs. 6-9.

1. A common power flow base case of the interconnection is shared among all the RTOs, with each RTO sending network status of its transmission facilities to a central repository. After the status update is applied by each RTO to the actual lines and transformers in the base case, *each RTO will develop all the Eqs. 6-9 including those of the other RTOs from the updated base case* (with contingency simulation, where the constraint is a post-contingency constraint).

2. A common power flow base case of the interconnection is shared among all the RTOs, with each RTO sending network status of its transmission facilities to a central repository. After the status update is applied by each RTO to the actual lines and transformers in the base case, *each RTO will develop its own Eq. 6 from the updated base case, and send them to the other RTOs whenever the network status changes*.

3. A central computer system, which maintains a common power flow base case of the interconnection, receives the real-time network status from all RTOs, develops Eqs. 6-9 for all RTOs and sends these equations to each RTO, whenever the network status changes. Each RTO must use those equations defined for the other RTOs but may include more equations for its own network to take care of local constraints that do not affect the other RTOs.

The third method seems to offer simplicity of implementation, greater assurance of consistency, and a convenient venue for standardization.

The likely and most reliable source of data for a common power system model for an interconnection, in the near term, is an interconnection-wide transmission planning model. Such models already exist for the three North American interconnections and are maintained regularly by working groups. They are updated seasonally to reflect new generation resources, load forecasts and changes in the transmission network. These are better sources than what could result from attempts to piece together power system models currently residing on energy control center computers, even though the CIM/XML format has gained acceptance among the major EMS vendors for exchanging power system models.

Common Definition of Cohesive Electrical Zones

The common power system model for an interconnection easily consists of 40,000 buses, 50,000 lines and thousands of generators. Theoretically, for maximum accuracy, it would be useful to retain the granularity of the bus-level modeling when each RTO solves its SCD problem. However, this is not practical or necessary because engineering approximations can be applied to balance accuracy with computational effort. The success of the Eastern Interconnection in using the PTDF[6] and OTDF[7] approximations of power flow equations in the Interchange Distribution Calculator (IDC) for implementing the NERC Transmission Loading Relief (TLR) procedure is proof that engineering approximations work. In fact, in the current IDC, the granularity of the dispatch variables is at the control area level, and not at the generation or load bus level. Effort is underway at NERC to improve the granularity model of the IDC and the E-tags system which supports the IDC. In this paper, we use the term "cohesive electrical zone" to mean a granularity level above the bus level but generally below the control area level.

A Cohesive Electrical Zone (CEZ) is defined to be a group of buses which exhibit the following behavior with respect to other Cohesive Electrical Zones and with respect to all major reliability constraints (or reliability flowgates) as defined in an interconnection:

1. The "operating state" of the buses in a CEZ is defined to be the sum of the MW generation output of all generators within the CEZ minus the sum of the MW load of all load buses within the CEZ. In short, we call it the "net MW injection" of the CEZ. If it is positive, there is more generation than load in the CEZ. If it is negative, there is more load than generation in the CEZ.

2. When the "operating state" of a CEZ is changed as a single variable, it is assumed that the MW generation or load at each bus within the CEZ is changed in a constant proportion to the "operating state." The set of constant proportions is called the participation factors.

3. When a power transfer has its source inside one CEZ (denoted by i) and its sink inside another CEZ (denoted by j), its effect on a reliability constraint (denoted by flowgate k) is approximated by the $PTDF_{k,i-j}$ or the $OTDF_{k,i-j}$, for that pair of CEZ with respect to the reliability constraint, where the "net MW injection" of a CEZ is treated as a single variable. Note that the PTDF (or OTDF) on a flowgate k due to a transfer from a source i to a sink j can be calculated from ($GSF_{k,i}$ - $GSF_{k,j}$), where GSF is the generation shift factor[8] on a flowgate defined with respect to a system swing bus for a given network status (pre- or post-contingency).

4. The accuracy[9] of a CEZ definition with respect to a reliability constraint and a sink CEZ can be measured by the accuracy of the PTDFs or the OTDFs when the source is allowed to be any member bus of the source CEZ. This is shown in the example of Figure 3-2, where the buses encircled by the CEZ 1 are being tested for cohesiveness. The idea is that if the buses belonging to the same CEZ are chosen well, any bus within the CEZ can singly or jointly with other buses in the CEZ participate in the "net MW injection" of the

[6] PTDF stands for power transfer distribution factor and equals the fraction of a power transfer schedule which flows through a particular parallel path.
[7] OTDF stands for outage transfer distribution factor and equals the fraction of a power transfer schedule which flows through a particular parallel path in the post contingency situation with a given contingency outage.
[8] GSF can be viewed as the PTDF or OTDF of a bus with respect to a flowgate when the sink is the system swing bus.
[9] Accuracy may be measured by the standard deviation (σ) of the GSF for the members of a CEZ, with respect to a reliability constraint. The overall accuracy of a CEZ may be defined as the maximum σ with respect to all reliability constraints which lie outside the CEZ.

CEZ, and the effect on the reliability constraint is approximately the same, as measured by the PTDFs or the OTDFs.

5. The accuracy of a CEZ definition with respect to all reliability constraints and all potential sink CEZs can be measured by the worst accuracy obtained in item 4 above, when the accuracy calculated in item 4 above is repeated for all CEZs and for all reliability constraints. By switching the measurement of accuracy from PTDF (or OTDF) to GSF, the searching algorithm for identifying member buses of a CEZ can be greatly simplified. With this approach, those buses which together have a variation in their $GSF_{k,i}$ with respect to flowgate *k* with a standard deviation σ_k that lies within a tolerance level of ε, are cohesive with respect to that flowgate *k*. To ensure cohesiveness with respect to all flowgates that lie outside the CEZ, the requirement is that the σ_k for all these flowgates must all lie within the tolerance ε.

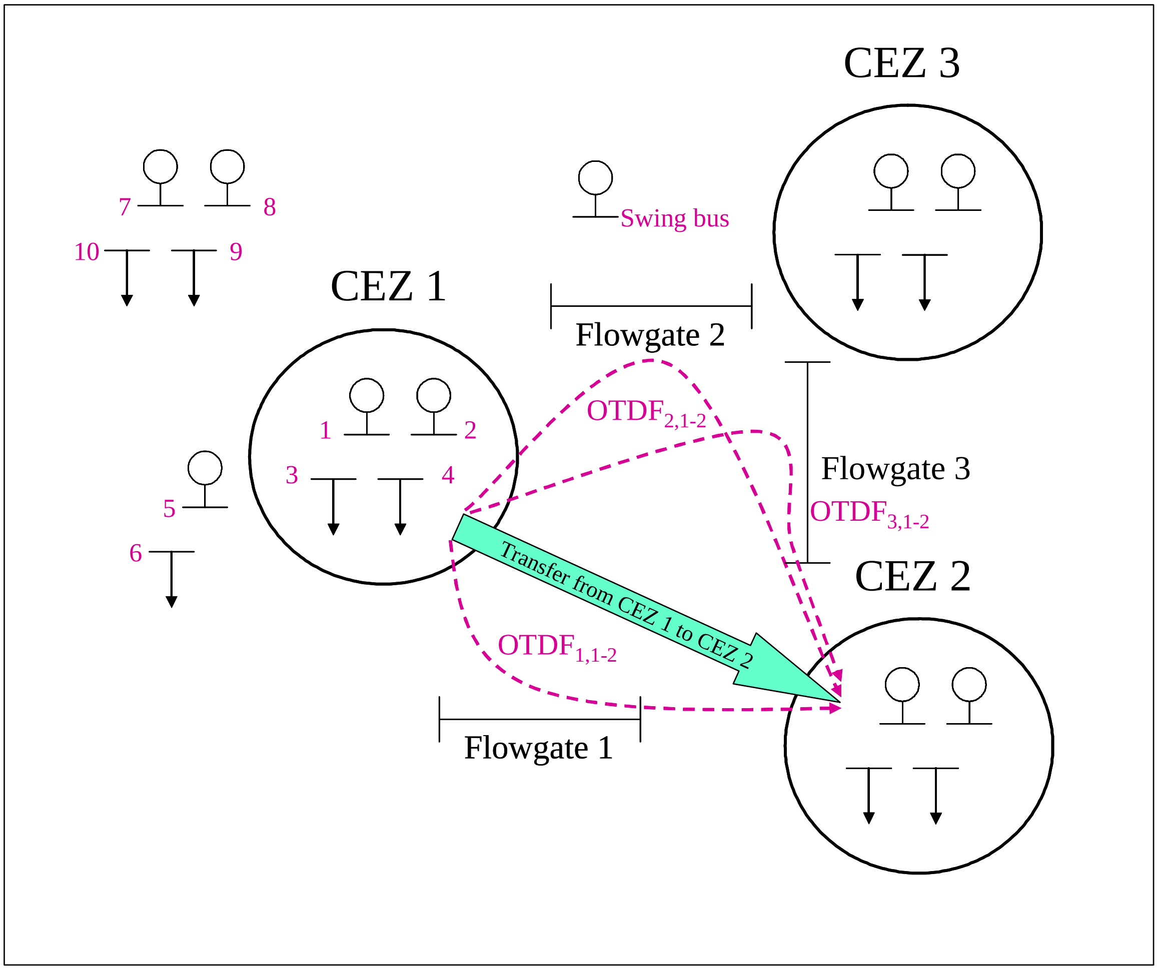

Figure 3-2 An Example for Defining a Cohesive Electrical Zone (CEZ)

An example of realistic GSF values for seven flowgates in the Eastern Interconnection when the granularity is at the control area level is shown in Figure 3-3. Only control areas in the ECAR west, MAPP, VACAR, TVA and Southern Company are shown in this graph. The points are connected by straight lines with a color code that shows the potential CEZ (assuming ECARW, MAPP, VACAR, and TVA/SOCO are being considered as four CEZs). The red lines represent ECARW control areas, the yellow lines represent MAPP control areas, the blue lines represent the TVA/SOCO control areas, and the purple lines represent the VACAR control areas.

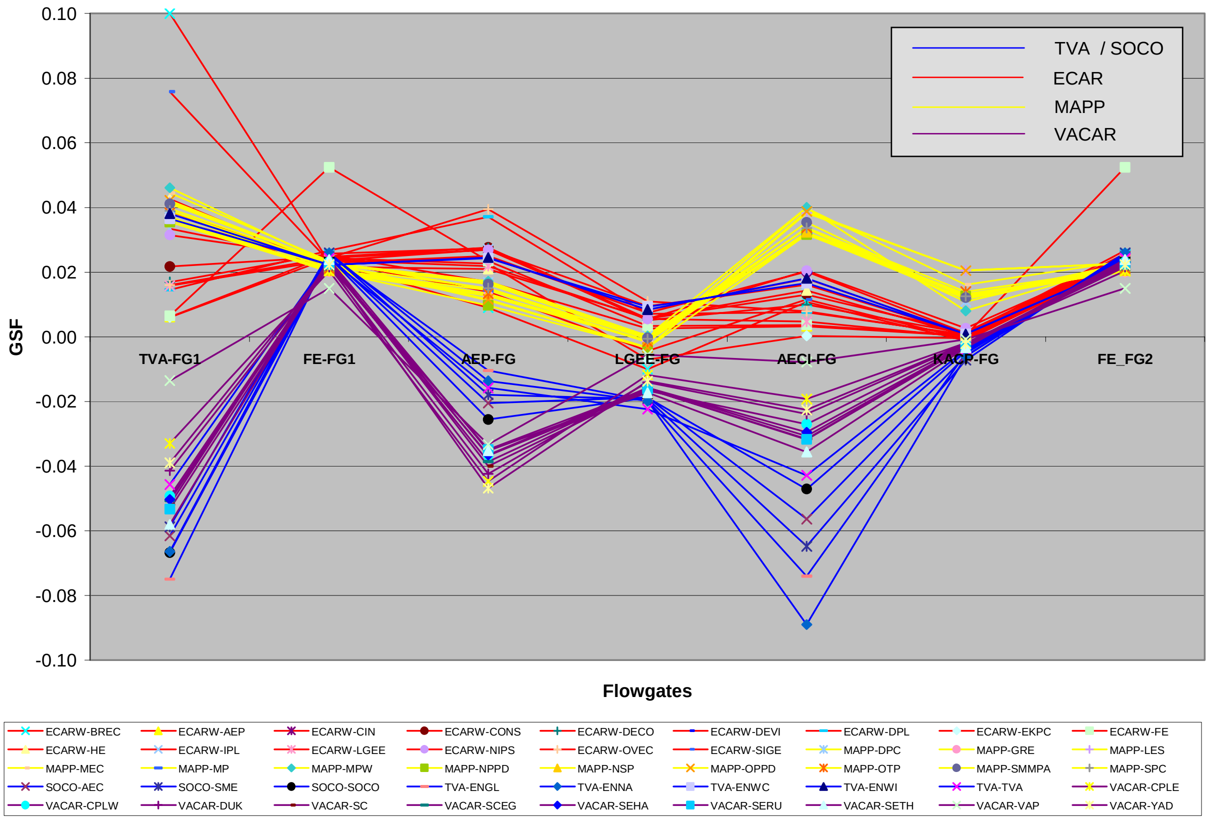

Figure 3-3 An Example of GSF Clusters Defining 4 Potential Cohesive Electrical Zones

From Figure 3-3, it can be observed that the yellow lines stay close to one another for all seven flowgates. In other words, the MAPP control areas seem to form a cohesive zone. The red lines show a fair amount of scattering except for the sixth (KACP) flowgate. This indicates that ECARW should be split into more than one CEZ. The purple lines show good clustering except for the first (TVA-FG1), third (AEP-FG), and fifth (AECI-FG) flowgates. This suggests that VACAR should be split into more than one CEZ. The blue lines show bad clustering for two control areas (ENWI and ENWC) which have GSFs of different signs for the first, third, fourth and fifth flowgates from the main group of TVA/SOCO. The clustering for the fifth flowgate (AECI-FG) is very bad for the blue lines. The reason for this is that the flowgate lies within the overall geographical area of TVA and SOCO. In other words, in power transfer takes place among the control areas within TVA and SOCO, they have different impacts on this flowgate. However, if transfers take place between these control areas and those outside of the TVA/SOCO area, their impacts on the other six flowgates are quite similar. Thus, the conclusion may be that TVA/SOCO (except for ENWI and ENWC) is an acceptable CEZ with respect to flowgates outside the CEZ.

Having demonstrated the feasibility of the Cohesive Electrical Zone concept and the means of measuring the degree of cohesiveness, a simple algorithm is proposed for identifying the CEZs for a specified tolerance ε.

Proposed Algorithm for Identifying Cohesive Electrical Generator Zones

1. Compute the $GSF_{k,i}$ of all generators *i* for all flowgates *k*.
2. Start with a control area and its largest generator that has not already been assigned to a CEZ and initialize the mean values and the variances (σ^2) of the $GSF_{k,i}$ for all flowgates, for the new CEZ. If there is no more unassigned generators, stop.
3. From the rest of the unassigned generators, select the one that, when added to the running values of the mean and variance from Step 2, gives the lowest variance which satisfies the tolerance condition, i.e., ($\sigma^2 < \varepsilon^2$).
4. If one is found, assign it to the new CEZ, and go back to Step 3. Otherwise, close the new CEZ and go back to Step 2 to start a new CEZ.

Proposed Algorithm for Identifying Cohesive Electrical Load Zones

1. Compute the $GSF_{k,i}$ of all load buses *i* for all flowgates *k*.
2. Start with a control area and its largest load bus that has not already been assigned to a CEZ and initialize the mean values and the variances (σ^2) of the $GSF_{k,i}$ for all flowgates, for the new CEZ. If there is no more unassigned load buses, stop.
3. From the rest of the unassigned load buses, select the one that, when added to the running values of the mean and variance from Step 2, gives the lowest variance which satisfies the tolerance condition, i.e., ($\sigma^2 < \varepsilon^2$).
4. If one is found, assign it to the new CEZ, and go back to Step 3. Otherwise, close the new CEZ and go back to Step 2 to start a new CEZ.

Note that with both algorithms, it is possible to increase or decrease the number of CEZs by changing the tolerance ε. With a looses tolerance, there will be fewer CEZs (coarser granularity). With a tighter tolerance, there will be more CEZs (finer granularity).

Advantages of Standardized Cohesive Electrical Zones

The advantages of using CEZs as part of the data glue to connect several RTOs into a single Virtual RTO are as follows:

1. It reduces the amount of data that need to be exchanged.
2. The data exchanged are aggregated data and do not reveal commercially sensitive data about the outputs of individual generators.
3. Definition of the CEZs will be objectively done with a uniform accuracy applied across the interconnection. The CEZs are electrically meaningful and most likely will bear a close relationship with LMP pricing zones.

4. Real-time data of the "net MW injection" for each CEZ for a portfolio (defined as a set of CEZ whose sum of net MW injections equals zero) is an accurate replacement for E-tags, for coordinated congestion management between RTOs, which may be used by the IDC, and/or the LMP computation engines of an RTO. The data may be put into E-tag format (extended to include balanced portfolios) and exchanged with the IDC or LMP computation engines. Parallel flow impacts of an RTO's entire portfolio (suitably defined to allow for non-zero net interchanges with other RTOs) can be assessed through the superposition principle used in the IDC.

5. A historical archive of all the hourly "net MW injections" of all CEZs in the entire interconnection will be extremely valuable to do financial resettlement calculations that properly account for parallel flow impacts caused by each RTO's portfolio on the transmission facilities of other RTOs. Having these data available will enable financial settlements to be made, which can implement equitable sharing of market savings among the different States within an RTO. It will also enable the implementation of an Automatic Transmission Toll Collection (ATTC) system, which is based on the allocation of toll charges according to the actual usage of new and existing transmission facilities in the entire interconnection. These two topics will be discussed in Section 5.

6. The characterization about the CEZs as defined for each RTO may be used by each RTO to develop an equivalent power system model for all the other RTOs in the interconnection. For example, each CEZ may be reduced to a single equivalent bus. All lines in the RTOs which are defined in Eq. 7, 8 and 9 may be kept in the equivalent model as original circuits, while all other circuits not being monitored could be turned into equivalent lines. This enables each RTO's control center to have a good equivalent model of the entire interconnection, with details inside its own RTO network, and all these models will be consistent with one another.

Real-Time Data

There are four types of real-time data which must be shared among the RTOs in order that each RTO can solve its security-constrained economic dispatch problem, as formulated in Eqs. 4-9. They are: (1) network status changes, (2) results of the dispatch decision for each RTO, (3) actual measurement data, and (4) market price data.

The network status data need to be updated only when there are changes. In the Eastern Interconnection, the SDX data exchange system for reliability coordinators currently provides this functionality for scheduled outages. The enhanced SDX can include timely updates of forced outages. Line or transformer outage status data are already used by the IDC to update the PTDF and OTDF every hour. More frequent sharing of status updates among the RTOs will improve the consistency and accuracy of the power system model used by each RTO.

The results of the dispatch decision, in the general case, should include not only the generation output values of each RTO's resources, but also load level data, other system parameters, and other control variables that affect power flows, e.g., phase angle settings of phase-angle regulators (PAR). Before implementation is possible, standard definitions of what constitute these decision variables, system parameters, and control variables must be agreed among the RTOs in an interconnection.

The majority of the data representing the dispatch decision of an RTO's SCD problem can be aggregated into the form of the "net MW injection" of each CEZ within an RTO. As mentioned previously, such data can be put into the format of a new version of E-tags, adapted to handle balanced portfolios of both positive and negative MW injections. Where an RTO's dispatch decision includes a source or a sink outside of the RTO's system, representing net export or net import of the RTO, those sources and sinks are part of the balanced portfolio of the RTO. In order for the parallel flow effects of these external sources and sinks to be modeled correctly, their locations must also be identified by the external CEZs where they physically reside.

Real-time load data for a CEZ may not be measurable directly in an RTO's control center. However, it does not preclude the use of planning data suitably adjusted by the current peak load of a control area or a sub-region of an RTO. Because most loads are not dispatchable to a significant degree, less accuracy in their actual values is not critical. Their inaccuracy can be compensated for by the use of real-time line flows on critical flowgates. Consider Eq. 6 describing the constraints on line flows, repeated below:

$$\underline{g}_A(\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) \le \underline{T}_{A,\max} \qquad Eq.6$$

If the net loads of the CEZs are not known accurately, when their values are entered into the left hand side of the equations to compute the line flows, the accuracy may be slightly off. However, if the actual line flows are metered and available, a correction term can be added to Eq. 6, so that the corrected left hand side is compared to the line flow limits on the right hand side. This is shown below in the corrected constraint below:

$$\underline{g}_A(\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) + \Delta flow \le \underline{T}_{A,\max} \qquad Eq.16$$

$$where$$

$$\underline{g}_A(\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) + \Delta flow = Measured\ \ flow \qquad Eq.17$$

In other words, Eq. 17 is used to calculate $\Delta flow$, which is then used in Eq. 16 as the substitution for Eq. 6 for solving the security-constrained dispatch problem for the next time step.

In summary, Table 3-1 shows the list of real-time data that should be exchanged and shared among the RTOs in order to achieve a Virtual RTO for coordinated congestion management. One existing data communication channel is the NERC ISN (Interregional Security Network). Other data would be required if global market price convergence is desired. What these other data include should be studied further.

Type of Real-time Data	Data Description	Notes
Network Status	Line or transformer planned outage schedule (specified to the hour, if possible)	
	Line or transformer forced outage status (updated in real-time)	

Dispatch Decision	Total net MW injection of each Cohesive Electrical Zone (both generation and load CEZs) as computed by an RTO's SCD for the current time interval	Data may be fed from each RTO's control center into the NERC ISN network as they are obtained from the SCD solution. Or data may be combined into a complete portfolio of all CEZs and external sources and sinks, and put into E-tag format.
	Other control variables decided by an RTO's SCD, e.g., phase angle of Phase Angle Regulators and FACTS device settings, which have a significant effect on MW power flow distribution.	
Actual Measurement Data	Actual net MW injection of each CEZ as measured in real-time by an RTO's control center (for both generator and load CEZs)	This real-time data would be useful for adjacent RTOs to monitor how quickly the dispatch decision of an RTO is implemented and results in actual changes in the dispatch.
	Actual line flows for critical flowgates	
	Actual line ratings for critical flowgates	
	Actual net exports or imports for external sources and sinks	
Market Price Data	Zonal Locational Marginal Prices	Preliminary, more research is needed.
	Zonal LMP curves in both the incremental and the decremental directions	Preliminary, more research is needed.

Table 3-1
List of Real-time Data to be Exchanged to Achieve a Virtual RTO

In summary, with sufficient and proper data exchange among the RTOs in real-time, it is possible for the RTOs in an interconnection to be consistent with one another in terms of a common power system model. That will enable coordinated decisions to be made by each RTO, with the mutual impacts properly considered while each RTO is making its decision.

Coordinated Congestion Management by a Virtual RTO

In the near term, it is unlikely that an entire interconnection will have implemented LMP as the means of congestion management. Also, without an interconnection-wide SCD computer taking over congestion management for the whole interconnection (which is unrealistic in the near term), existing RTOs, ISOs, ITPs, etc. will have to coordinate their internal congestion management with the other operating entities in the same interconnection.

This discussion uses the context of a Virtual RTO to illustrate a practical method for coordinated congestion management in an interconnection. The principles discussed here may be applied to any combination of congestion management methods, because the fundamental power flow problem is the same.

First, we can use the four-RTO system shown in Figure 3-1 in this discussion to illustrate the proposed procedure for this coordination.

Example of Coordinated Congestion Management Procedure

1. Each RTO has the base case power system model of the entire interconnection set up specifically for its own use. This most likely involves developing equivalent power system models of the other RTOs centering around the CEZs of the other RTOs.

2. Each RTO sends and receives the network status of lines and transformers to a central repository.

3. Each RTO updates the power system model of the interconnection in its control center to reflect changes in the network status in the interconnection. (This step is performed only when there are significant changes, as the computer time required may be significant.)

4. Each RTO sends and receives the real-time data listed in Table 3-1 (for the dispatch decision and actual measurement data). This is done continuously as new data are received.

5. Each RTO solves its SCD problem (or an equivalent congestion management problem) following Eq. 4 to 9, with the assumptions that the dispatch decisions of the other RTOs remain constant. This step is done at the regular frequency at each RTO, determined by the speed of the control center computer.

6. Each RTO sends its dispatch solution immediately to the other RTOs. Note that Steps 4, 5, and 6 are repeated in a loop based on the speed of processing for each RTO, so that the processing speeds of other RTOs' control centers do not hold up its reliability and market functions.

Reliability Backstop System for Coordinated Congestion Management

The coordinated congestion management procedure described above may not produce a feasible solution under all circumstances. It is conceivable that under heavy congestion in the interconnection due to a combination of high load levels and high inter-RTO power transfers, a globally feasible solution would involve dropping firm loads in one or more RTOs in the interconnection. In such events, there are issues of equity among the RTOs as to the proper shares of the load shedding. It is also conceivable that alternatives may exist which involve re-dispatching the inter-RTO transfers, instead of load shedding. In other words, instead of taking as unchangeable the market schedules across more than one RTO, it may be necessary and desirable to reschedule them in such a way that congestion can be relieved.

It may be that with sufficient iterations between the RTOs using the Coordinated Congestion Management Procedure above, some of these problems may be solved. However, reliability may be severely impacted in the mean time. It may also be possible that the coordinated procedure above may not work well during the time period of a day when load is increasing or decreasing rapidly. Thus, to handle these potentially unanticipated situations, it is vital that a reliability backstop system be available to maintain reliability in the interconnection.

The Interchange Distribution Calculator (IDC) is the reliability backstop system at the present time in the Eastern Interconnection. The question is how the IDC will evolve in the near future to remain relevant and vital as the reliability backstop in the new world where LMP is implemented in part or all of the interconnection.

Because not all reliability coordinators in the Eastern Interconnection will adopt LMP at the same time, if indeed they would all do so in the near future, it is critical that the reliability backstop system must function properly during the transition period. Ideally, the transition should take place smoothly with the reliability backstop system evolving into one that supports LMP systems as well as hybrid systems.

The concept proposed in this paper may offer such a smooth transition for the IDC. Central to this transition are the following elements:

- Standard definition of Cohesive Electrical Zones (CEZ) accepted by all reliability coordinators, which are also implemented in the LMP for modeling external sources and sinks for an RTO that implements the SCD. At the same time, the IDC will change from a granularity of Control Areas to a granularity of CEZs.

- E-tags will transition from E-tag 1.7 to a hybrid tagging system with the ability for an RTO to send its entire balanced portfolios (firm and non-firm) of generation and load dispatch results from its SCD solution to the IDC. Such portfolio E-tags would model the internal dispatch of the RTO in the granularity of the CEZ, and the external sources or sinks in the same granularity of the standard CEZs accepted by all. Point-to-point source-sink transactions would continue to be tagged in the existing format. The modification to the IDC and the E-tag standards would be minimized with this approach.

- TLR (Transmission Loading Relief) procedures will be modified to accommodate the portfolio tags. When an MW amount of relief is required on a flowgate, the IDC would apply the priority order of both types of E-tags (firm and non-firm, etc.) and compute the equitable shares of cuts allocated to all E-tags. The exception for the portfolio E-tags is that the RTO which owns that portfolio would be given the flexible on how to redispatch its SCD solution in order to achieve a given amount of MW loading relief on the impacted flowgate. Because these flowgates should already be modeled as constraints in an LMP RTO's SCD program, it would be simple for the reduction to be modeled as a change to that constraint's limit.

It appears that this system would accommodate the needs of an LMP RTO and the needs of other reliability coordinators who rely solely on the IDC as the coordinated congestion management tool, because the IDC's accuracy will not be reduced by the LMP RTOs. Instead, with improved granularity due to the CEZ definitions, the accuracy of the IDC will be improved.

At the minimum then, the modified IDC will continue to serve as the reliability backstop system. Beyond just maintaining the IDC as the reliability backstop system, it is conceivable that some other tool may help those reliability coordinators not operating under the LMP to manage congestion economically. The Community Activity Room concept described in the Appendix offers that possibility. The TLR procedure is based on equitable sharing of pain and not based on the most market-efficient way to relieve congestion. The CAR provides the suggestion of how to relieve congestion with the minimum reduction in MW transactions. If that information can be combined with the economic factors for the affected transactions, then it is possible that a cost-effective TLR can be computed. However, the problem is how to financially compensate for such market-based TLR. The SCD is one way of achieving that, whether it is implemented in an LMP RTO or as an economic dispatch for a non-market system, using true operating costs. Another solution is to implement an SCD for the entire interconnection. While the latter may not be achievable in the near term, it may be an acceptable mechanism for doing settlement calculations that share market savings among the constituent RTOs. This will be discussed later in this paper.

Role of Market Towards a Global Market Equilibrium

A global market equilibrium may be defined to be the optimal solution to an SCD problem for the entire interconnection. As shown in Eq. 10-15, the differences between the global solution and the aggregation of individual RTO's SCD solution are due to the following:

- All dispatch decisions are optimized at the same time.
- Individual RTO's load and resource balance equations are replaced by one interconnection-wide load and resource balance equation.

This effectively opens up the possibility of free flow (apart from reliability constraints) of generation across the RTOs, resulting in greater variations of imbalances in each RTO, which of course result in greater variations of imports and exports for each RTO. This translates into the cheaper energy flowing into areas which previously have more expensive local generation. The total cost of the entire interconnection will be lower.

If the power marketers play an active role in purchasing and selling power between RTOs, and even across an intermediary RTO, such economic power exchange can take place through the competitive market. If adjacent RTOs also engage actively in economy interchange between themselves, such exchanges would also have similar effects of moving the market towards the global market equilibrium. Therefore, through the human market loops of the power marketers and through the semi-automatic economy interchange between adjacent RTOs, it is arguable that global market efficiency can be achieved, if conditions are repetitive and timely information is available to the marketers and to the RTOs for such transactions to take place in a timely manner.

Role of RTOs and Automation Towards a Global Market Equilibrium

Just as the market human loop should facilitate global market convergence, it is technically possible to automate the process through inter-RTO economy transactions. The idea is to computerize the manual process of intercompany economy interchanges that took place routinely among control area operators before restructuring.

In those days, a control area operator knew its system incremental cost, called system lambda at any time. He could telephone another control area operator and find out if the other system's system lambda was sufficiently different from his so that it would save money for both systems to engage in a split-savings economy interchange. The information exchange was manual and not explored to the maximum extent. With computer and data exchange, it is possible to speed up the process and explore all bilateral opportunities among the RTOs within an interconnection.

The key for making this happen is to describe the system lambda of each RTO as a set of bid price curves for each Cohesive Electrical Zone within its system. It is necessary to recognize the different CEZs because the LMPs may be different depending on the CEZs. In order for the transactions to be feasible, the sources of the bids must be associated with their CEZs. It is also necessary to put an upper MW limit on each bid price curve.

Each RTO will derive from its system the bid price curve for each CEZ that has available generation capacity for export. It may decide to bid into one or more RTOs within the interconnection. In doing so, it may allocate the available capacity from each CEZ into separate bids for the other RTOs who are likely to purchase. This may require rule-making from FERC for clarification that an RTO may not bid into the other RTOs more capacity in total than it has available at any time. At subsequent bid intervals, an RTO may revise its allocations to achieve more transactions.

An RTO will receive bids from its own market as well as the bid curves from the other RTOs. It will then solve its LMP problem just like the formulation in Eqs. 4 to 9, except that the objection function is now shown in Eq. 4a and the constraints also include the new decision variables, which are the amounts to accept from the bids of the other RTOs, which consist of multiple bids from the different CEZs.

$$
\begin{aligned}
&\textit{Minimize } C(\underline{x}_A)+\sum C(e_B)+\sum C(e_C)+\sum C(e_D) && Eq.4a\\
&\textit{subject to}:\\
&h_A(\underline{x}_A, e_B, e_C, e_D)=0 && Eq.5a\\
&\underline{g}_A(\underline{x}_A,\underline{x}_B,\underline{x}_C,\underline{x}_D,e_B,e_C,e_D)\le \underline{T}_{A,\max} && Eq.6a\\
&\underline{g}_B(\underline{x}_A,\underline{x}_B,\underline{x}_C,\underline{x}_D,e_B,e_C,e_D)\le \underline{T}_{B,\max} && Eq.7a\\
&\underline{g}_C(\underline{x}_A,\underline{x}_B,\underline{x}_C,\underline{x}_D,e_B,e_C,e_D)\le \underline{T}_{C,\max} && Eq.8a\\
&\underline{g}_D(\underline{x}_A,\underline{x}_B,\underline{x}_C,\underline{x}_D,e_B,e_C,e_D)\le \underline{T}_{D,\max} && Eq.9a\\
&\textit{with}\\
&\underline{x}_B,\underline{x}_C,\underline{x}_D \qquad \textit{assumed fixed}
\end{aligned}
$$

Note that Eq. 5a preserves the energy balance in each RTO. This means that as each RTO is solving its LMP problem as formulated here, the combined solution of all the RTOs also preserves the energy balance in the interconnection. Also, because Eqs. 6a – 9a explicitly considers the congestion effect of the to-be-scheduled economy purchases, the solution for each RTO also respects the reliability constraints of the entire interconnection.

In summary, the Inter-RTO LMP iterative procedure may be structured as follows:

1. Each RTO derives its bid price curve for each CEZ with surplus generation capacity and decides how much of the available capacity to submit to the other RTOs as bidders for

selling economy energy. This is done in the Day-Ahead Market and also at each regular time interval in the Real-Time Market.

2. Each RTO, having received bids from all parties including the other RTOs, solves its LMP problem as formulated in Eqs. 4a-9a. Its dispatch decision is immediately communicated to the other RTOs.

3. Each RTO re-evaluates its bid price curves and available capacities for each CEZ and submits a new set of bids to the other RTOs. The process then continues into the next time interval.

Note that for the Day-Ahead Market, the process will iterate several times until convergence is reached. Convergence is considered achieved when two successive passes through the entire set of RTOs produce the same result for every RTO. The converged results will set the Day-Ahead Market. In the Real-Time Market, the iterative process will take place in real-time, because each iteration may take 5 minutes of computer time. If one waits for the convergence before implementing the decision, it may not be fast enough to keep up with load changes. Thus, it is necessary to trade off perfect optimality with the reality of operations.

This iterative process will be demonstrated in the third example in the next section.

Summary of Virtual RTO Architecture

As a summary of the concepts and the iterative processes described in this section, Figure 3-4 puts them in their relationship with one another, and with the current NERC IDC and the E-tags systems.

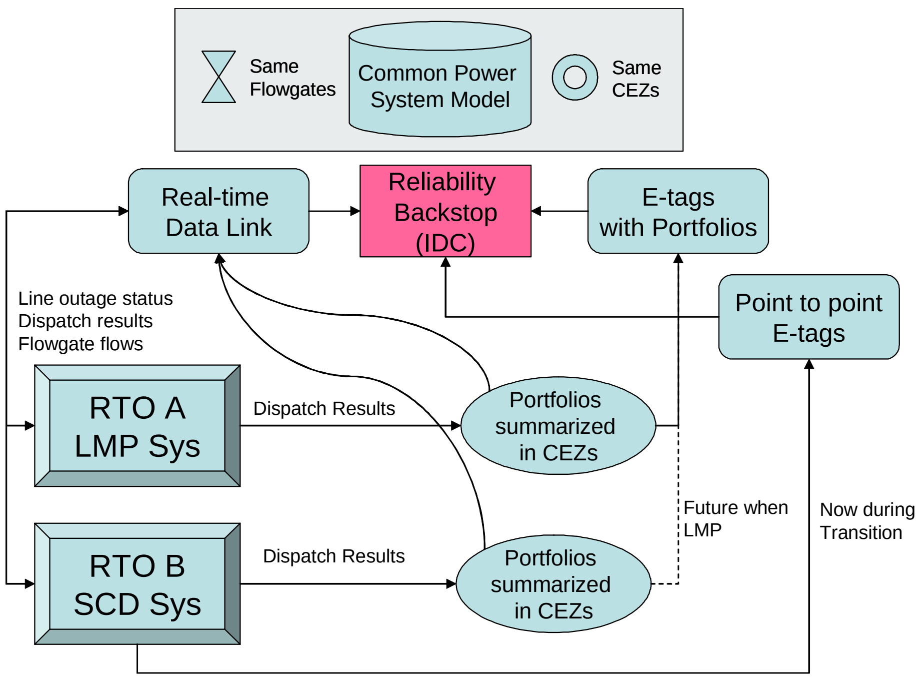

Figure 3-4 Virtual RTO Architecture with Glue

As shown in the top part of the diagram, the Common Power System Model is consistently applied to all modeling, along with standard flowgates and CEZs in the entire interconnection. The diagram is illustrated for two RTOs but it can be extended to include more RTOs. An RTO may use LMP or a Security Constrained Economic Dispatch (SCD). As each RTO solves its coordinated dispatch problem (LMP or SCD), the dispatch results are summarized in terms of net injections of the CEZs, and then sent in two paths as balanced portfolios. There could be a firm set and a non-firm set of balanced portfolios. For an RTO that implements LMP, the balanced portfolios will be sent as a new type of E-tags to the IDC and also sent as real-time data through the NERC ISN. Other real-time data will also be exchanged through the real-time network. The fact that point-to-point E-tags can co-exist with Portfolio E-tags in the IDC is shown in the diagram. As an RTO moves from the current TLR-based transaction management to an LMP-based system, it can switch from point-to-point E-tags to the Portfolio E-tags, and the transition can be managed without degrading the accuracy of the IDC. In fact, moving the industry to the implementation of CEZs for point-to-point E-tags will also improve the accuracy of the IDC in the mean time, due to enhanced granularity in the IDC model.

4
ILLUSTRATIVE EXAMPLES

Basic Assumptions and Data

In this section of the paper, a small but realistic sample system is used to illustrate the concept of the Virtual RTO. The data are derived from the equations used by the CAR Painter program, described in the Appendix, which model the Eastern Interconnection for the 2002 summer peak load condition. Of the over 130 control areas modeled in the Summer 2002 PSAST study, a small set is retained as representative CEZs for four RTOs. The configuration of these four RTOs follow the general shape of Figure 3-1. In effect, RTO A may be interpreted to be PJM, RTO B to be MISO, RTO C to be TVA and RTO D to be SETRAN. The compositions of PJM and MISO include the currently known new entities.

Table 4-1 shows the composition of the four RTOs, in terms of the CEZs. For the purpose of illustration, three CEZs are assumed to participate in each RTO as external PSEs, for economy sales or purchases. For simplicity, one CEZ from each RTO is chosen. An arbitrary set of bid prices ($/MWh) is assumed for al the CEZs. When the dispatch is optimized, each CEZ is assumed to have a positive and a negative MW limit, generally at + or -1000 MW.

	RTO A		RTO B		RTO C		RTO D	
CEZ #	CEZ Name	Bid Price ($/MWh)	CEZ Name	Bid Price ($/MWh)	CEZ Name	Bid Price ($/MWh)	CEZ Name	Bid Price ($/MWh)
1	A1	30.0	B1	29.0	C1	28.0	D1	30.0
2	A2	31.0	B2	30.0	C2	27.0	D2	31.0
3	A3	25.0	B3	28.0	C3	26.0	D3	25.0
4	A4	33.5	B4	30.0	C4	29.0	D4	33.5
5	A5	24.0	B5	31.0	C5	30.0	D5	24.0
6	A6	24.5	B6	29.0	C6	31.0	D6	34.0
7	A7	34.0	B7	32.0	C7	32.0	D7	35.0
8	A8	35.0	B8	28.5	C8	33.0	D8	36.0
9	A9	36.0	B9	26.0	A12*	33.0	D9	33.0
10	A10	33.0	B10	25.0	B10*	25.0	A12*	33.0
11	A11	37.0	B11	23.0	D3*	25.0	B10*	25.0
12	A12	33.0	B12	30.5			C2*	27.0
13	A13	34.5	B13	25.0				
14	A14	35.5	B14	24.0				
15	B10*	25.0	B15	25.5				
16	C2*	27.0	B16	24.5				
17	D3*	25.0	A12*	33.0				
18			C2*	27.0				
19			D3*	25.0				

CEZ = Cohesive Electrical Zones
* denotes bidders external to the RTO market area
Bid prices are completely arbitrary assumptions.

Table 4-1 Composition of Four Example RTOs

Note that the PSEs external to each RTO are denoted by an asterisk. For demonstrating the reliability constraints, ten (10) constraints were selected from the PSAST study. These are post-contingency constraints on flowgates that were found to be critical in the North to South direction (5 of them), South to North direction (4 of them) and one in theWest to East direction. Note that there is hardly any difference between the North to South and the West to East direction, because most North to South flows are also West to East and vice versa. These ten constraints and their MW limits are shown in Figure 4-1.

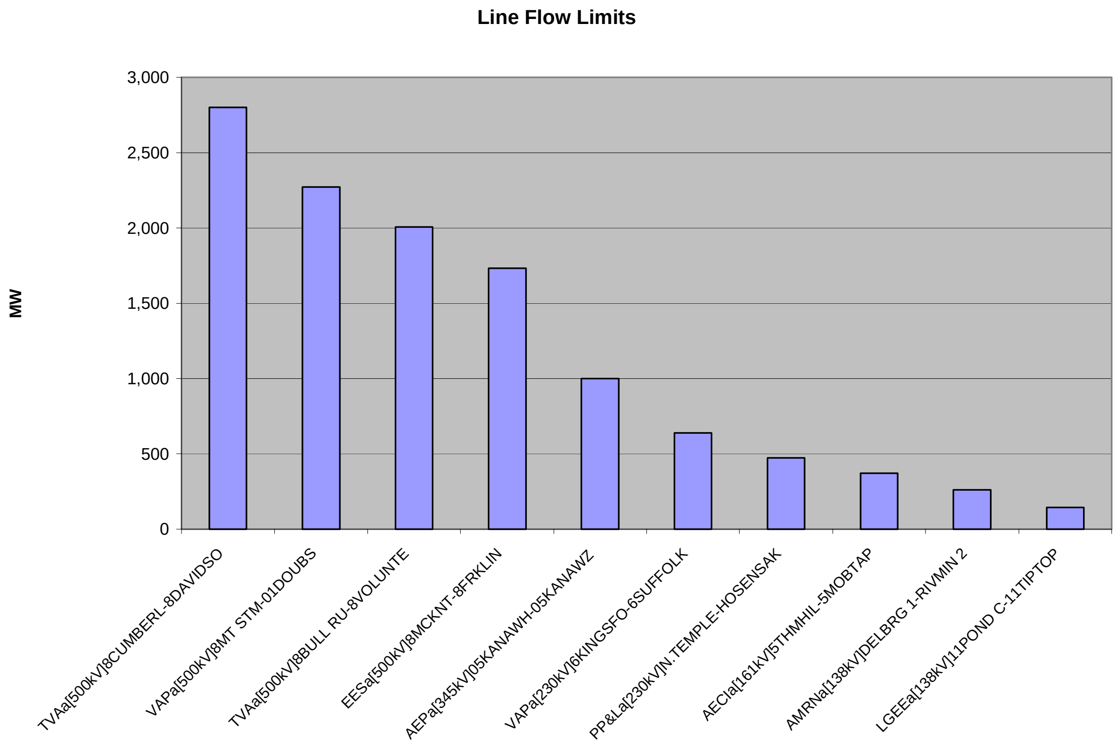

Figure 4-1 Ten Line Flow Constraints Modeled in Example System

The approximate locations of these flowgates are depicted in Figure 4-2.

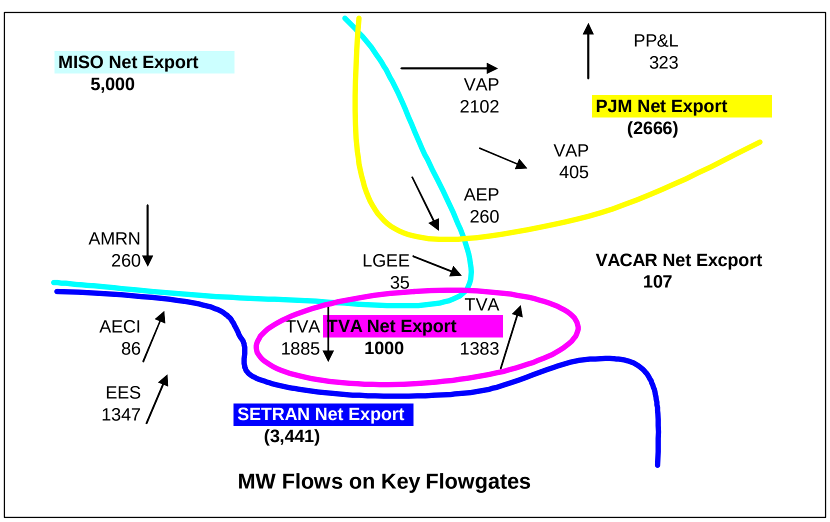

Figure 4-2 Ten Line Flows in Example System

The direction of the arrows show the general direction of the flows, e.g., the TVA Cumberland-Davidson line is shown with a downward arrow to indicate that it is a North to South bottleneck, whereas the TVA Bull Run – Volunteer line is shown as an upward arrow to indicate that it is a South to North bottleneck. Also shown in Figure 4-2 are the RTO's net export or import for the initial conditions of Example 1. If the value is positive, it is a net export. If the value is negative, it is a net import. The sum of these four values is zero.

Each flowgate constraint is represented as a linear inequality with a constant coefficient (α) multiplying each CEZ's incremental generation output (x) relative to the reference value. In other words, the general constraint equation as shown in Eq. 6 below is implemented as Eq. 18.

$$\underline{g}_A(\underline{x}_A, \underline{x}_B, \underline{x}_C, \underline{x}_D) \le \underline{T}_{A,\max} \qquad Eq.6$$

$$\alpha_1 x_1 + \alpha_2 x_2 + \alpha_3 x_3 + \alpha_4 x_4 + \alpha_5 x_5 + ... + cons \le T_{\max} \qquad Eq.18$$

In Eq. 18, the $T_{\max}$ is the line flow limit in MW and the *cons* is a constant which represents the flow on the line when all incremental generation variables are set to zero. These inequalities were directly obtained from the CAR Painter.

Excel Worksheet Model of LMP Solutions for Four RTO and the Interconnection

The capability of Microsoft Excel software to solve an optimization problem with constraints was used to develop a worksheet model of four RTOs in an interconnection, with LMP solution applied to each of the RTO separately and also to the entire interconnection.

One worksheet with all five optimization problems stored on the worksheet was used as the computation engine. That worksheet also contains summary tables and pictures of the results (exactly as Figure 4-2 and 4-3.) After each solution is solved, the resulting worksheet is saved with a different file name. That worksheet with the solution is then used to solve the next optimization problem and the new worksheet is saved under a different name again. This process is continued one iteration after another, as a way of passing the successive solutions as the initial conditions for the subsequent iteration.

Finally, a summary worksheet is created from extracted results from the worksheets for the iterations.

Example One - Assumptions

For the first example, the initial conditions were set up to represent moderate North to South and West to East flows under moderately high load levels. Each RTO was optimized to dispatch its CEZ outputs including its three external CEZs to balance its load, subject to the ten flowgate constraints. After all four RTOs were dispatched sequentially, all four RTOs' loads were balanced and all ten flowgate constraints were within limits. In fact, one flowgate (AMRN) was at its limit of 260 MW. This is typical of SCD. At the optimal solution, usually one or more constraints are at the limits. The flows and the net exports are shown in Figure 4-2. A more detailed tabulation of the results of the initial conditions of Example One is shown in Figure 4-3.

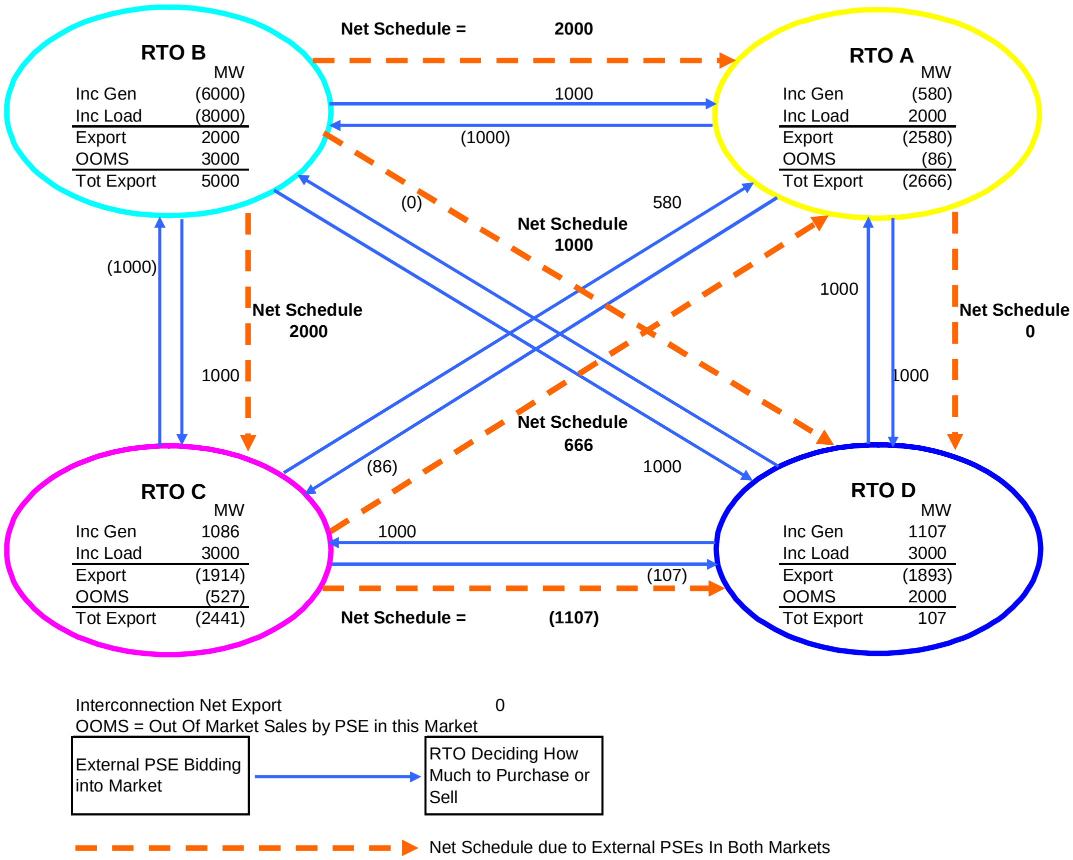

Figure 4-3 Summary of Initial Conditions for Example One

The main factor affecting the initial conditions is the incremental load (shown as *Inc Load* in Figure 4-3) for each of the four RTOs. The SCD problems are framed in terms of changes in each CEZ's generation relative to a reference case value. The reference case from which the incremental load is defined is where the generation values (x) in Eq. 18 were set to zero. When the *Inc Load* is positive, Eq. 18 for a particular flowgate is adjusted to reflect higher transmission loading. When the *Inc Load* is negative, Eq. 18 is adjusted to reflect lighter transmission loading.

For each RTO, for a given value for *Inc Load*, the energy balance equation as represented by Eq. 5 below is implemented as Eq. 19, where the sum of the incremental CEZ generation values (which can be either positive or negative) equals the *Inc Load*.

$$h_A(\underline{x_A}) = 0 \qquad Eq.5$$

$$x_1 + x_2 + x_3 + x_4 + x_5 + \ldots = Inc\,Load \qquad Eq.19$$

With this approach, the SCD problem will find the optimal solution for each RTO such that the incremental generation of all the CEZs of an RTO including the external PSEs will in total match exactly the incremental load change, whether it is an increase or a decrease. The result may be a net export or a net import for an RTO, depending on the relative bid prices of the internal CEZs of an RTO versus its external CEZs. Because each CEZ has its upper and lower limits (set generally to + or -1000 MW), for an incremental load increase of sufficient magnitude, the cheapest sources will eventually be used up and the flow impact will change as the location of the incremental CEZ moves around, affecting both flowgate constraints as well as changing net export or net import.

With this understanding, the *Inc Load* values in Figure 4-3 were input data. The results of the SCD for each RTO determine the values for *Inc Gen* and *Export*. *Inc Gen* is the sum of the internal CEZs' incremental generation output. *Export* is the sum of the external CEZs' incremental generation output.

Pictorially, the *Export* value for an RTO is broken down into the three parts that go to the other three markets, through three blue arrows with the arrow-point coming into the RTO. For example, for RTO B in Figure 4-3, the *Export* value is 2000 MW. Of the three incoming blue arrows, the one from RTO A shows a value of -1000 MW. That means the scheduled purchase from the PSE in RTO A is actually a sale of 1000 MW from RTO B to the PSE in RTO A. The incoming blue arrow from RTO C also has a negative value of -1000 MW, so the interpretation is the same as for RTO A. The third incoming blue arrow, coming from RTO D, is zero. Therefore, the sum of these three incoming arrows is -2000 MW, which indicates an export of 2000 MW. Thus this is shown as a 2000 MW value for *Export*.

Because the PSEs located inside an RTO can participate in the other three markets, there are also three outgoing blue arrows originating from each of the RTO to the other RTOs. The total amount of sales or purchases from the PSEs inside an RTO destined for the external markets is called Out Of Market Sales (*OOMS*). For example, RTO B shown in Figure 4-3, has a total *OOMS* of 3000 MW, with 1000 MW going to each of the other three RTOs. This amount of *OOMS*, whether it is known by RTO B or not, contributes to the net export of RTO B, which equals the sum of *Export* and *OOMS* and is shown as *Tot Export* in Figure 4-3. Finally, the net value of the external PSEs' schedules in the OOMS between two RTOs is shown by the orange dashed arrows, with the *Net Schedule* in Figure 4-3. In other words, the *Net Schedule* is the algebraic sum of the two opposite blue arrows.

The existence of *OOMS* brings up a coordination issue. It is a good idea for PSEs to be able to participate in these out-of-market sales or purchases, as it is the means for achieving a global market equilibrium with human market activities. However, the result is that the RTOs in the interconnection must all be aware of these *OOMS* values because they contribute to the flows in the interconnection. Fortunately, with the proposed approach of each RTO communicating with each other the results of its SCD in the form of the entire portfolio of CEZ output values, including these external PSEs, the coordination among the RTOs for handling *OOMS* is now achieved.

Convergence Experiment with Example One – Rapid Load Pickups

The objective of the experiment with Example One is to illustrate the ability of the Coordinated Congestion Management Procedure (CCMP) to converge even under highly stressed conditions where within one iteration time interval (5 minutes), each RTO experiences a large increase in its load. The scenario of load increases is as follows:

Iteration 1 – RTO A dispatches its system to pick up 3000 MW of load

Iteration 2 – RTO B dispatches its system to pick up 3000 MW of load

Iteration 3 – RTO C dispatches its system to pick up 3000 MW of load

Iteration 4 – RTO D dispatches its system to pick up 2000 MW of load

Iteration 5 – RTO A dispatches it system with load unchanged from Iteration 1

Iteration 6 – RTO B dispatches its system with load unchanged from Iteration 2

Iteration 7 – RTO C dispatches its system with load unchanged from Iteration 3

Iteration 8 – RTO D dispatches its system with load unchanged from Iteration 4

After Iteration 4, the solutions of the subsequent iterations remain unchanged from that of Iteration 4, demonstrating convergence to a feasible solution for the interconnection which is also optimal for each of the four RTO. As a comparison with the global optimal LMP solution for the entire interconnection, Iteration 9 was also run.

Iteration 9 – Taking the solution from Iteration 8 (which is the same as the solutions from Iterations 4, 5, 6, and 7) as the initial guess, the entire interconnection is dispatched under the global LMP problem.

The results of this convergence sequence are shown in Table 4-2.

Results for Example 1 (Convergence With Rapid Load Pickups)

Summary of Iteration Results	**Initial Conditions**	**RTO A Load + 3000 MW**	**RTO B Load + 3000 MW**	**RTO C Load + 3000 MW**	**RTO D Load + 2000 MW**	**Resolve RTO A**	**Resolve RTO B**	**Resolve RTO C**	**Resolve RTO D**	**Global LMP**
RTO Net Export	**Base Case**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
RTO A	(2,666)	(2,790)	(2,790)	(1,704)	(1,704)	(1,704)	(1,704)	(1,704)	(1,704)	(8,514)
RTO B	5,000	5,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	17,490
RTO C	(2,441)	(2,317)	(2,317)	(3,403)	(4,122)	(4,122)	(4,122)	(4,122)	(4,122)	(3,976)
RTO D	107	107	1,107	1,107	1,826	1,826	1,826	1,826	1,826	(5,000)
Total	0	(0)	0	(0)	0	0	0	0	0	0
Cost	**Base Case**	1	2	3	4	5	6	7	8	Global
RTO A	1,521	101,072	101,072	101,072	101,072	101,072	101,072	101,072	101,072	(104,506)
RTO B	(258,000)	(258,000)	(180,483)	(180,483)	(180,483)	(180,483)	(180,483)	(180,483)	(180,483)	251,287
RTO C	64,828	64,828	64,828	155,616	155,616	155,616	155,616	155,616	155,616	63,263
RTO D	63,195	63,195	63,195	63,195	135,280	135,280	135,280	135,280	135,280	(68,157)
Total	(128,456)	(28,905)	48,612	139,400	211,484	211,484	211,484	211,484	211,484	141,886
	Base Case	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
Congestion Index (Sum of MW Loadings Above 90% of Limits)	84	26	26	26	26	26	26	26	26	253
MW Flow	**Base Case**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
VAPa[230kV]6KINGSFO-6SUFFOLK	405	394	333	281	200	200	200	200	200	288
AMRNa[138kV]DELBRG 1-RIVMIN 2	260	260	260	260	260	260	260	260	260	260
LGEEa[138kV]11POND C-11TIPTOP	35	42	35	5	(13)	(13)	(13)	(13)	(13)	17
AEPa[345kV]05KANAWH-05KANAWZ	260	350	348	271	155	155	155	155	155	678
TVAa[500kV]8CUMBERL-8DAVIDSO	1,885	1,903	1,946	1,854	1,758	1,758	1,758	1,758	1,758	2,466
PP&La[230kV]N.TEMPLE-HOSENSAK	323	310	308	290	291	291	291	291	291	317
EESa[500kV]8MCKNT-8FRKLIN	1,347	1,247	1,133	577	484	484	484	484	484	219
TVAa[500kV]8BULL RU-8VOLUNTE	1,383	910	531	375	169	169	169	169	169	541
AECIa[161kV]5THMHIL-5MOBTAP	86	94	115	122	125	125	125	125	125	125
VAPa[500kV]8MT STM-01DOUBS	2,102	2,034	2,009	1,844	1,779	1,779	1,779	1,779	1,779	2,271

Table 4-2 Results of Example One (Convergence Experiment Under Rapid Load Pickups)

The values of RTO Net Exports and the Cost of each RTO show that convergence was achieved after Iteration 4. A Congestion Index was defined as the sum of the MW loadings that exceed 90% of the line flow limits of the ten flowgates. The numbers showed that congestion was reduced immediately with Iteration 1 and that the global LMP solution actually results in much higher congestion in the interconnection. The latter observation is actually expected because with global LMP dispatches, there will be more interregional power flows which lead to greater congestion. In other words, market efficiency is achieved by a tradeoff with congestion or reliability.

The bottom part of Table 4-2 shows the line flows on the ten flowgates for each iteration and again confirms convergence after Iteration 4.

The fact that convergence is achieved only after one round of iteration around the four RTOs is quite amazing, under the rapid load pickups simulated in this scenario. The actual timing of these Iterations should be clarified. Iteration 1, 2, 3 and 4 can be staged 5 minutes apart, assuming that each RTO can solve its SCD and communicate the results to the next RTO in the chain within 5 minutes. Therefore, in this scenario, after RTO A solves its SCD, it waits for 15 minutes before it starts its second round of SCD (Iteration 5.) Therefore, the 3000 MW of load pickup in RTO A could take place in 15 minutes and the CCMP seems to converge rather easily.

Figure 4-4 plots the dispatch cost of each RTO and the total cost of the entire interconnection after each iteration. The increases in the costs mark the load pickups at the corresponding RTOs. The last iteration marked Global shows the costs of each RTO and the entire system when LMP was applied to the entire system. The difference between the Global solution and Iteration 8 shows dramatically the difference between the global solution and the CCMP solutions.

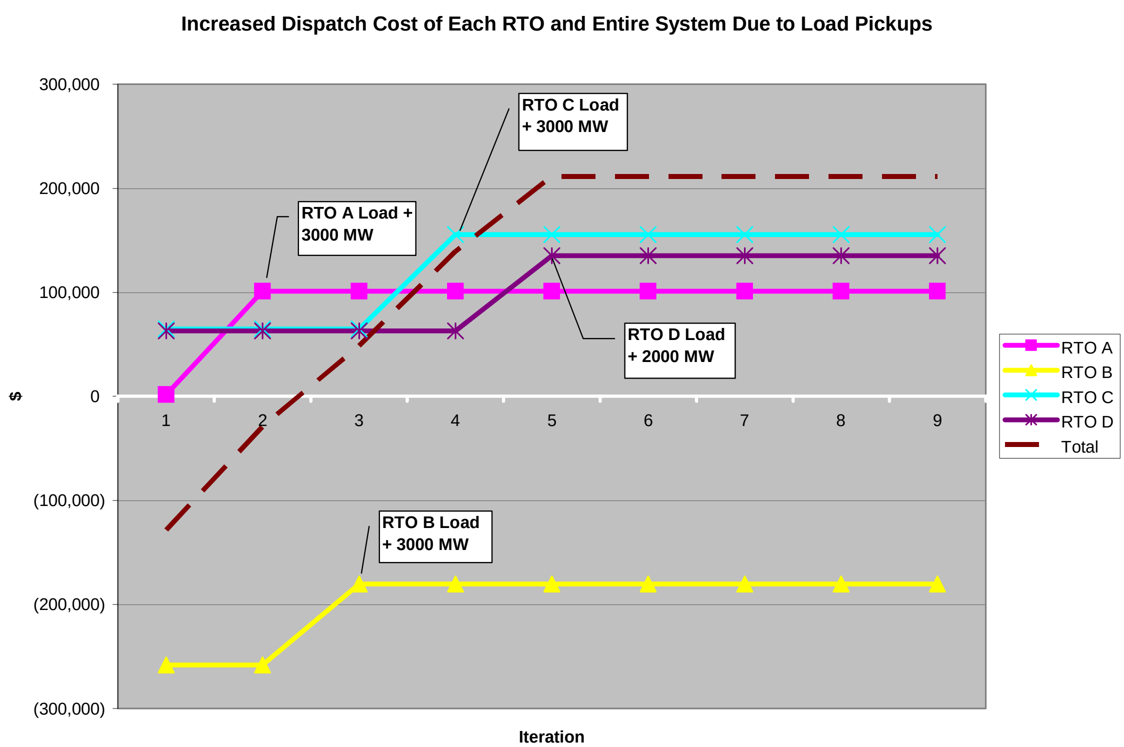

Figure 4-4 Dispatch Costs of Each RTO and Entire System for Each Iteration Under Rapid Load Pickups for Example One

Figure 4-5 shows the net exports of each RTO through the iterative process and also contrasts the Global solution with the CCMP solutions.

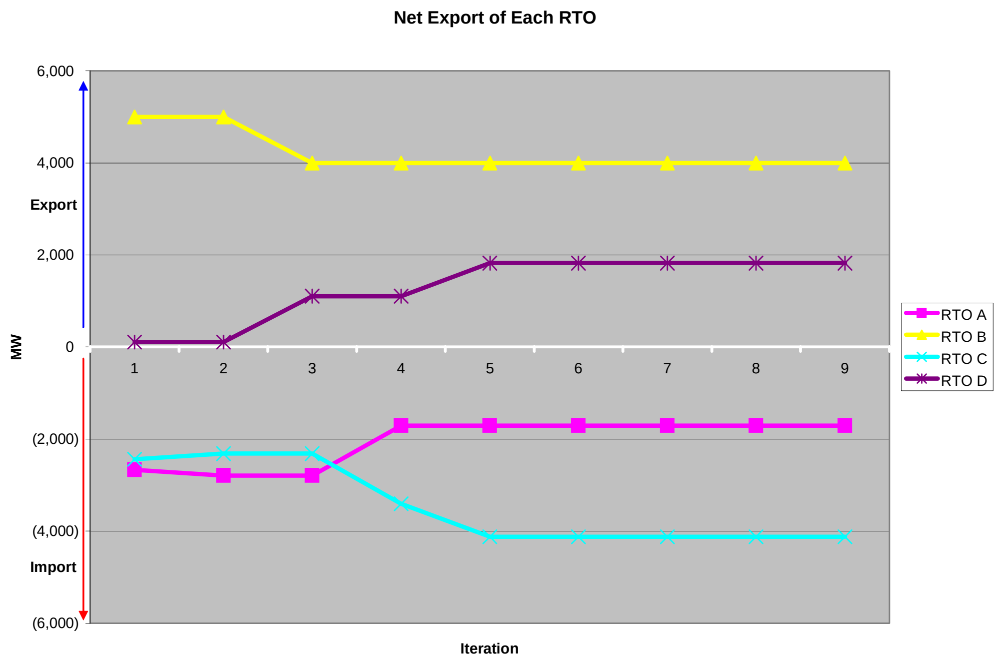

Figure 4-5 Net Export of Each RTO for Each Iteration Under Rapid Load Pickups for Example One

Figure 4-6 plots the congestion index for each iteration and shows the much higher congestion resulting from the Global solution as compared to the CCMP solutions.

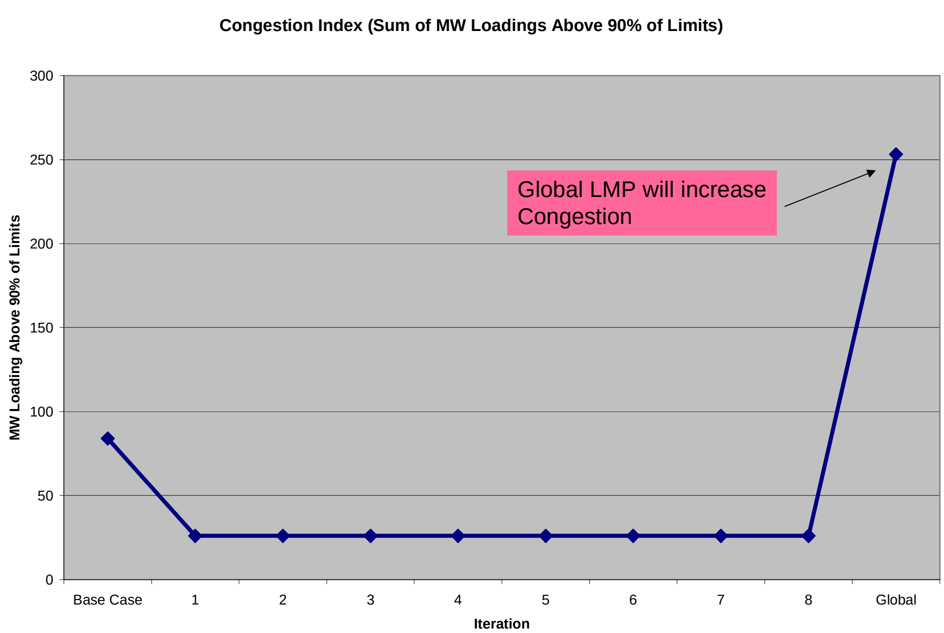

Figure 4-6 Congestion Index for Each Iteration Under Rapid Load Pickups for Example One

Figure 4-7 plots the line flows on the ten flowgates for each iteration and also the limits of two flowgates which were close to or at their limits.

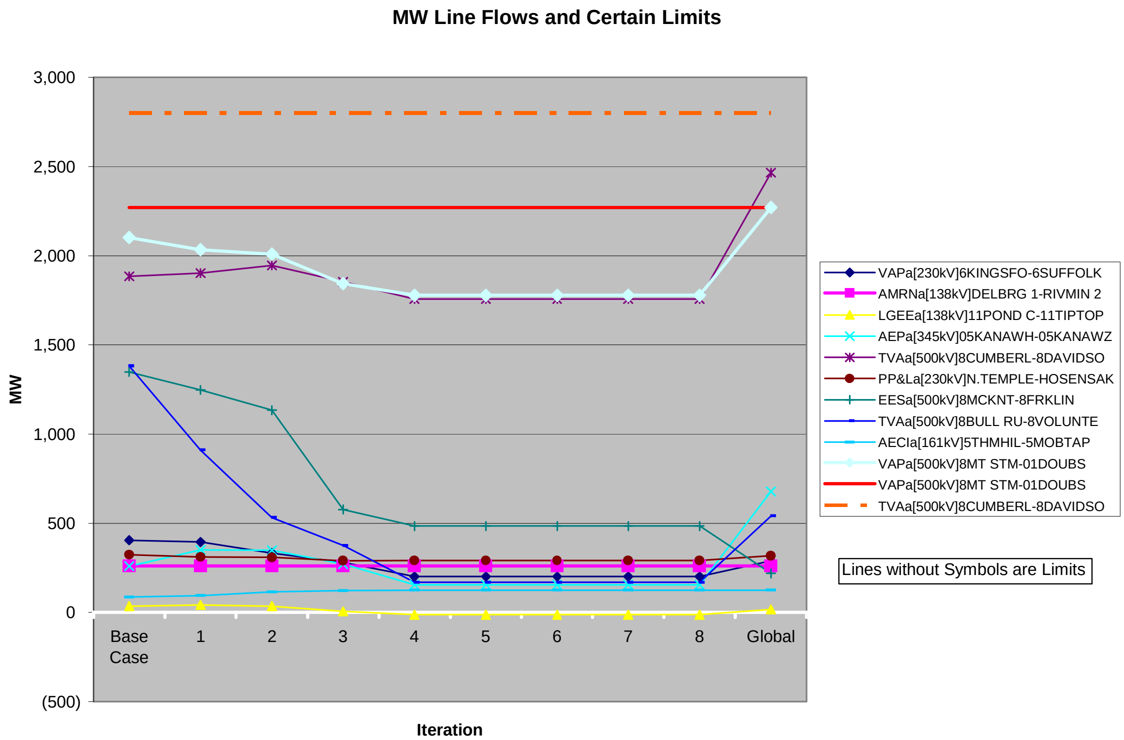

Figure 4-7 Line Flows and Limits for Each Iteration Under Rapid Load Pickups for Example One

Example Two - Assumptions

The objective of Example Two is to illustrate situations where the CCMP could fail somewhere during its process in the first round and yet still converge in the second round. To make this happen, the initial conditions for Example Two were set up under a moderately heavy South to North flow taken from a Global LMP solution for the interconnection. The CCMP is then applied to the initial conditions to let each RTO take turn to restore its energy balance. Thus, there were major shifts in the flow patterns after each RTO's solution. While each RTO is assumed to implement its SCD solution, there could be energy imbalances at the interconnection level. These imbalances in the iterative process are only mathematical difficulties showing the inability of the SCD to find a feasible solution. At the end of the iterative process, energy balance is achieved. This example is also used to illustrate the concept of shared savings among the RTOs. The initial conditions for Example Two are depicted in Figure 4-8.

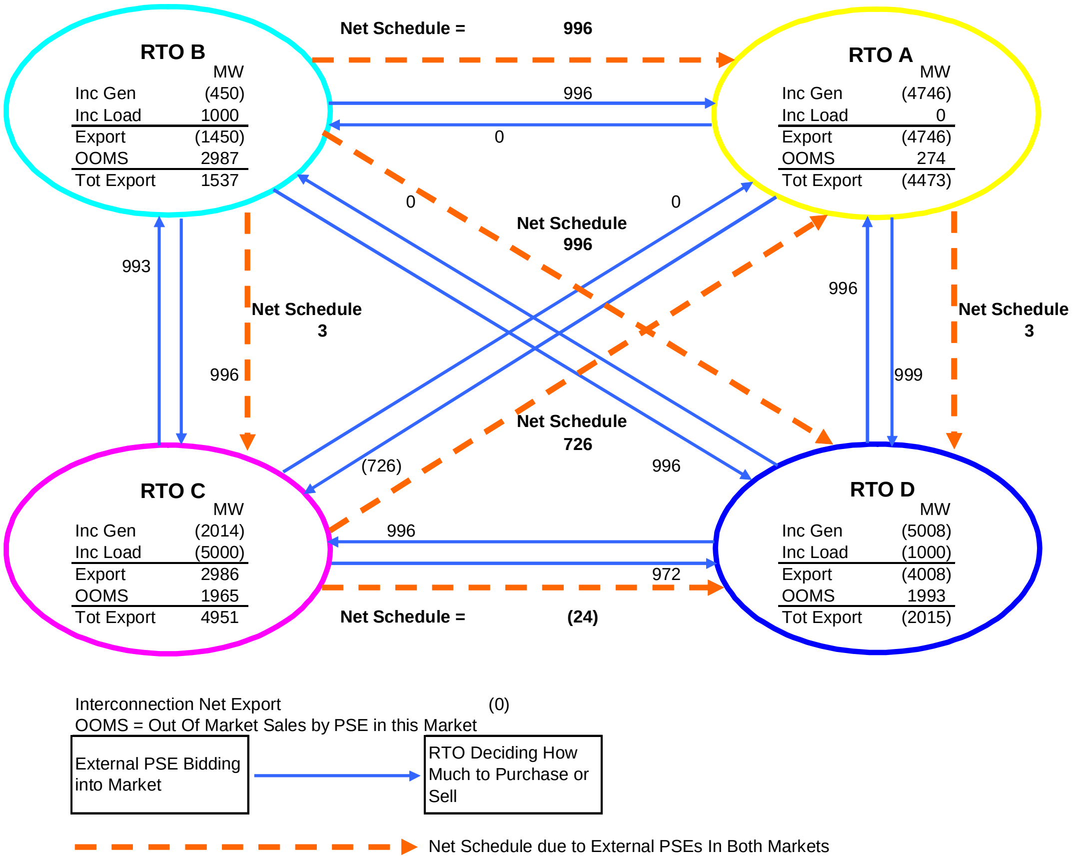

Figure 4-8 Summary of Initial Conditions for Example Two

Convergence Experiment with Example Two – Reconstruction for Shared Savings

In addition to using Example Two to illustrate potential convergence difficulties with the CCMP, the results of the CCMP dispatches are compared with the Global LMP solution to illustrate how that set of CCMP dispatches can be used as a reconstruction method for sharing savings due to a Global LMP solution to the constituent RTOs which will ensure that all constituents come out a winner in the single market operation. This topic will be discussed later in this paper.

The scenarios of the iterations are as follows:

Base Case – This is the Global LMP solution, used as the initial conditions.

Iteration 1 – RTO A dispatched its system to balance its own loads and resources and succeeded.

Iteration 2 – RTO B dispatched its system to balance its own loads and resources and succeeded.

Iteration 3 – RTO C dispatched its system to balance its own loads and resources and failed.

Iteration 4 – RTO D dispatched its system to balance its own loads and resources and succeeded but RTO C's imbalance remained.

Iteration 5 – RTO A dispatched its system to maintain its energy balance but RTO C’s imbalance remained.

Iteration 6 – RTO B dispatched its system to maintain its energy balance but RTO C’s imbalance remained.

Iteration 7 – RTO C dispatched its system and achieved energy balance.

Iteration 8 – RTO D’s new dispatch is unchanged from Iteration 4. Convergence for all four RTOs is achieved.

Iteration 9 – Global LMP with initial solution taken from Iteration 8 produced results very close to Base Case.

The results of this convergence sequence are shown in Table 4-3.

Results for Example 2 (Reconstruction for Shared Savings)

Summary of Iteration Results	**Global LMP**	**Solve RTO A**	**Solve RTO B**	**Solve RTO C**	**Solve RTO D**	**Solve RTO A Again**	**Solve RTO B Again**	**Solve RTO C Again**	**Solve RTO D Again**	**Global LMP**
Notes:	Initial solution	RTO A is balanced first.	RTO B is balanced next.	RTO C failed to balance.	RTO D is balanced but RTO C still not balanced.	RTO A is balanced but RTO C still not balanced.	RTO B is balanced but RTO C still not balanced.	RTO C is now balanced.	RTO D's balance is still valid.	Solution is slightly different from initial solution.
RTO Net Export	**Base Case**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
RTO A	(4,473)	(1,998)	(1,998)	(1,932)	(2,450)	(3,179)	(3,179)	(2,932)	(2,932)	(4,502)
RTO B	1,537	1,541	1,991	(4)	0	0	0	860	860	1,588
RTO C	4,951	5,222	5,230	4,101	4,129	4,858	4,858	2,553	2,553	4,914
RTO D	(2,015)	(2,012)	(2,012)	(2,008)	(481)	(481)	(481)	(481)	(481)	(2,000)
Total	(0)	2,754	3,212	157	1,198	1,198	1,198	0	0	0
Cost	**Base Case**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
RTO A	(141,902)	(60,223)	(60,223)	(60,223)	(60,223)	(63,228)	(63,228)	(63,228)	(63,228)	(114,694)
RTO B	(10,188)	(10,188)	2,510	2,510	2,510	2,510	2,500	2,500	2,500	(15,462)
RTO C	(52,502)	(52,502)	(52,502)	(128,890)	(128,890)	(128,890)	(128,890)	(161,754)	(161,754)	(63,466)
RTO D	(99,580)	(99,580)	(99,580)	(99,580)	(70,057)	(70,057)	(70,057)	(70,057)	(70,057)	(110,803)
Total	(304,172)	(222,494)	(209,795)	(286,183)	(256,660)	(259,664)	(259,674)	(292,538)	(292,538)	(304,425)
	Base Case	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
Congestion Index	485	268	260	300	227	234	234	260	260	484
MW Flow	**Base Case**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
VAPa[230kV]6KINGSFO-6SUFFOLK	607	588	584	637	558	545	545	592	592	607
AMRNa[138kV]DELBRG 1-RIVMIN 2	257	260	260	227	230	241	241	230	230	257
LGEEa[138kV]11POND C-11TIPTOP	110	110	110	138	126	114	115	143	143	111
AEPa[345kV]05KANAWH-05KANAWZ	650	696	707	689	607	581	581	661	661	649
TVAa[500kV]8CUMBERL-8DAVIDSO	2,193	2,191	2,199	2,150	2,105	2,071	2,070	2,249	2,249	2,196
PP&La[230kV]N.TEMPLE-HOSENSAK	304	310	308	310	319	319	319	315	315	304
EESa[500kV]8MCKNT-8FRKLIN	769	696	679	758	743	815	815	637	637	765
TVAa[500kV]8BULL RU-8VOLUNTE	2,008	1,602	1,537	1,696	1,619	1,757	1,755	1,590	1,590	2,007
AECIa[161kV]5THMHIL-5MOBTAP	119	126	128	89	90	87	87	106	106	120
VAPa[500kV]8MT STM-01DOUBS	2,271	2,271	2,268	2,271	2,271	2,271	2,271	2,271	2,271	2,271

Table 4-3 Results of Example Two

Note that in Table 4-3, the nonzero values of the Total Net Export for the entire interconnection are an indication of the infeasibility of some subproblem in the constituent RTOs. In other words, the SCD of an RTO failed to find a feasible solution without resorting to other means such as curtailing load. However, the fact that after the second round of iteration, a feasible solution is found is an indication that through the CCMP, it is possible to relieve congestion which an individual RTO may not be able to relieve without resorting to load curtailment. In other words, the CCMP may avoid load curtailment through the coordinated process. However, this example does not preclude other situations where congestion may be so high that even the CCMP will not avoid load curtailment. In such situations, having a readily available reliability backstop system like the IDC would be critically needed. The CCMP process may take more time than it is available when heavy congestion occurs.

Figure 4-9 plots the dispatch cost of each RTO and the total cost of the entire interconnection after each iteration. The failure of RTO C to find a feasible solution lasts from Iteration 3 through Iteration 6. The Base Case and the last iteration marked Global show the costs of each RTO and the entire system when LMP was applied to the entire system. The two solutions are very close in terms of costs. The difference between the Global solutions and Iteration 8 shows the difference between the global LMP solution and the CCMP solutions.

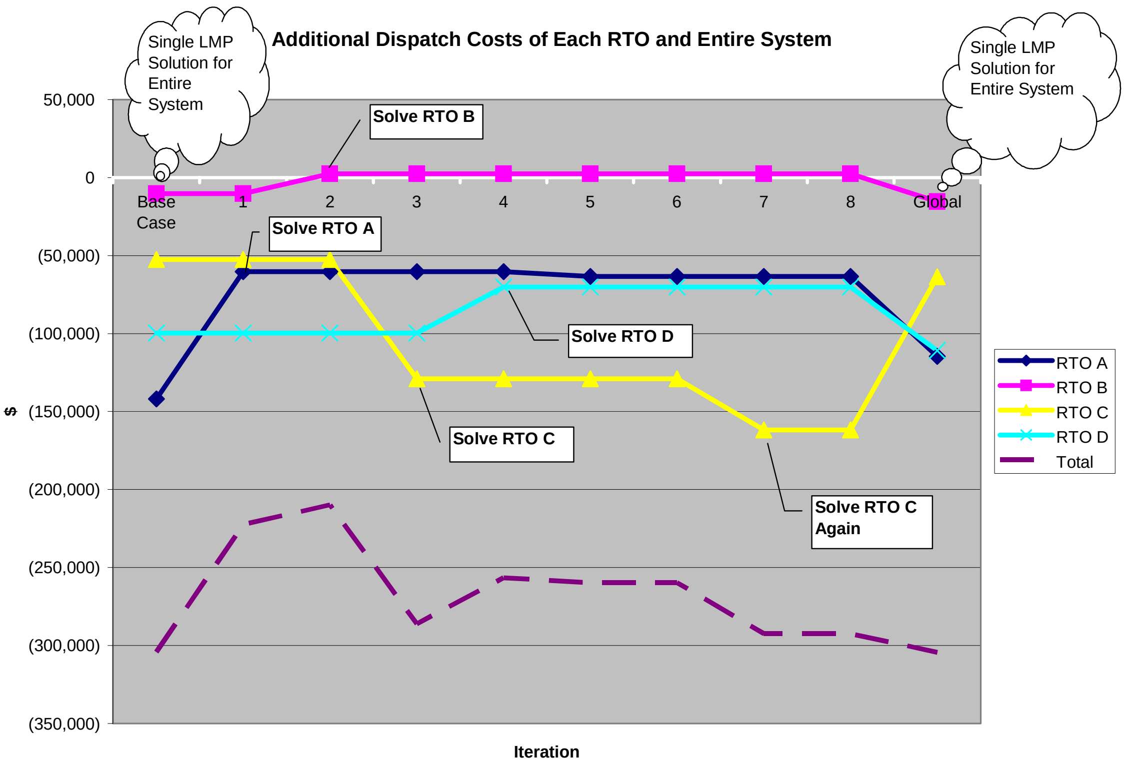

Figure 4-9 Dispatch Costs of Each RTO and Entire System for Each Iteration for Example Two

Figure 4-10 shows the net exports of each RTO through the iterative process and also contrasts the Global solution with the CCMP solutions.

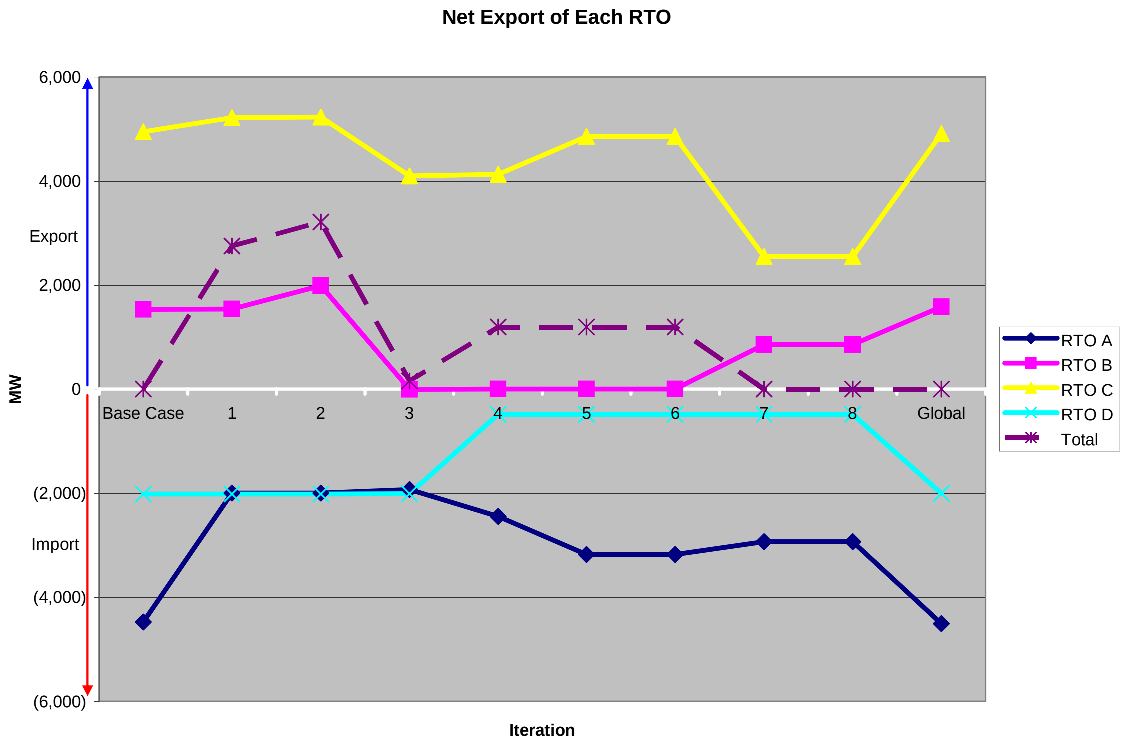

Figure 4-10 Net Export of Each RTO for Each Iteration for Example Two

Figure 4-11 plots the congestion index for each iteration and shows the much higher congestion resulting from the Global solution as compared to the CCMP solutions.

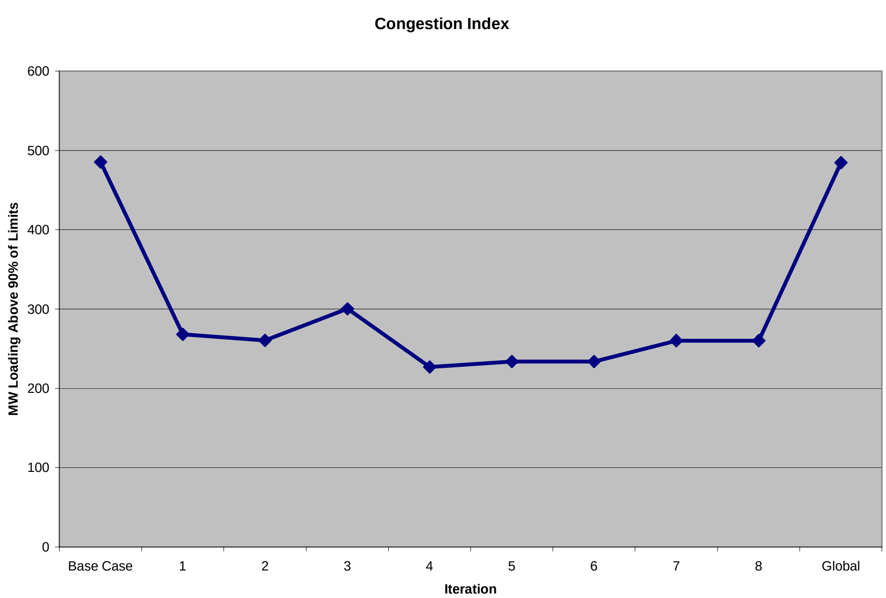

Figure 4-11 Congestion Index for Each Iteration for Example Two

Figure 4-12 plots the line flows on the ten flowgates for each iteration and also the limits of three flowgates which were close to or at their limits.

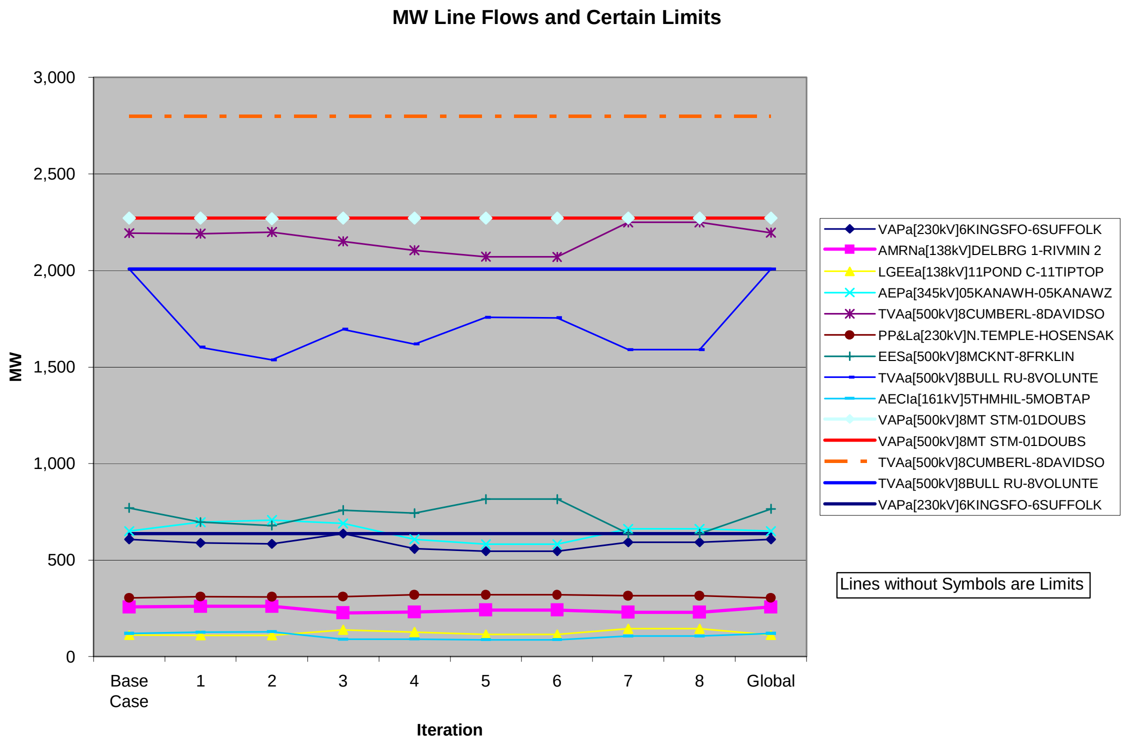

Figure 4-12 Line Flows and Limits for Each Iteration for Example Two

Example Three (Iteration Towards Global LMP Solution) - Assumptions

The objective of Example Three is to illustrate the proposed iterative process for the RTOs to bid into the other RTOs as sellers of economy energy. The initial conditions were set up to have a moderate increase in load, for a total of 5000 MW, such that there would be potential congestion conditions in the global solution. An algorithm in the Excel model was added for determining the lowest cost CEZ for each RTO which has available capacity to sell. To simplify the modeling, only one CEZ was used in each RTO for export. During the iteration process, the exporting CEZ was not changed even if the lowest-cost CEZ with available capacity changed. This helps convergence but also may restrict the convergence towards only a local optimal solution. If this method is implemented in an interconnection, these modeling limitations may be removed. The initial conditions for Example Three are depicted in Figure 4-13.

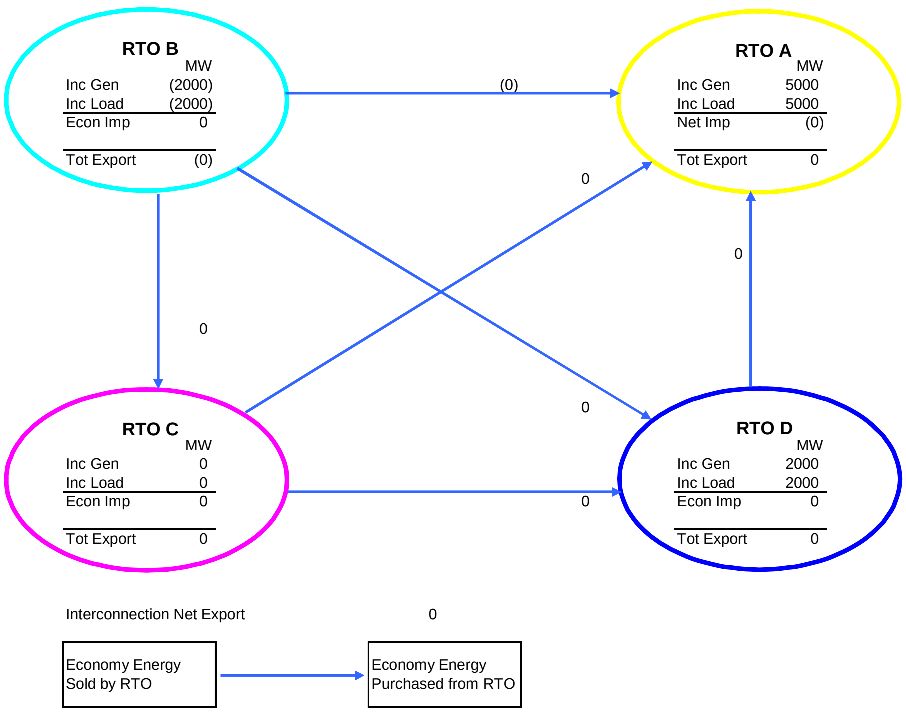

Figure 4-13 Summary of Initial Conditions for Example Three

Convergence Experiment with Example Three (Iteration Towards Global LMP Solution)

The scenarios of the iterations are as follows:

Isolated Case – This is the case where each RTO dispatches its own market, without purchasing economy energy from the other RTOs.

Iteration 1 – RTO A buys economy energy from the other RTOs, in the first pass.

Iteration 2 – RTO B buys economy energy from the other RTOs, in the first pass.

Iteration 3 – RTO C buys economy energy from the other RTOs, in the first pass.

Iteration 4 – RTO D buys economy energy from the other RTOs, in the first pass.

Iteration 5 – RTO A adjusts its purchases of economy energy from the other RTOs, in the second pass.

Iteration 6 – RTO B adjusts its purchases of economy energy from the other RTOs, in the second pass.

Iteration 7 – RTO C adjusts its purchases of economy energy from the other RTOs, in the second pass.

Iteration 8 – RTO D adjusts its purchases of economy energy from the other RTOs, in the second pass.

Iteration 9 – RTO A adjusts its purchases of economy energy from the other RTOs, in the third pass.

Iteration 10 – RTO B adjusts its purchases of economy energy from the other RTOs, in the third pass.

Iteration 11 – RTO C adjusts its purchases of economy energy from the other RTOs, in the third pass.

Iteration 12 – RTO D adjusts its purchases of economy energy from the other RTOs, in the third pass.

Iteration 13 – RTO A adjusts its purchases of economy energy from the other RTOs, in the fourth pass.

Iteration 14 – RTO B adjusts its purchases of economy energy from the other RTOs, in the fourth pass. It is observed that iterating beyond this iteration produces the same results for all RTOs. Thus convergence is reached.

Iteration Global LMP – From the results of the Base Case, the global LMP solution is derived.

The results of this convergence sequence are shown in Table 4-4.

Summary of Iteration Results	Isolated	1st Pass - RTO A	1st Pass - RTO B	1st Pass - RTO C	1st Pass - RTO D	2nd Pass - RTO A	2nd Pass - RTO B	2nd Pass - RTO C	2nd Pass - RTO D
Notes:	Initial solution	RTO A buys first.	RTO B buys next.	RTO C buys next.	RTO D buys next.	RTO A solves 2nd time	RTO B solves 2nd time	RTO C solves 2nd time	RTO D solves 2nd time
RTO Net Export	**Isolated**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
RTO A	-	(2,471)	(2,471)	(2,471)	(1,471)	(2,000)	(2,000)	(2,000)	(2,135)
RTO B	-	1,000	1,000	1,000	2,000	2,000	2,000	2,294	2,294
RTO C	-	1,000	1,000	1,000	1,294	1,294	1,294	1,000	1,706
RTO D	-	471	471	471	(1,823)	(1,294)	(1,294)	(1,294)	(1,865)
Total	0	0	0	0	0	0	0	0	0
Incremental Gen & Import	**Isolated**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
RTO A	5,000	5,000	5,000	5,000	4,000	5,000	5,000	5,000	5,135
RTO B	(2,000)	(3,000)	(2,500)	(2,500)	(3,500)	(3,500)	(2,000)	(2,294)	(2,294)
RTO C	0	(1,000)	(1,000)	0	(294)	(294)	(294)	(0)	(706)
RTO D	2,000	1,529	1,529	1,529	2,000	1,471	1,471	1,471	2,000
Total	5,000	2,529	3,029	4,029	2,206	2,677	4,177	4,177	4,135
Cost	**Isolated**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
RTO A	124,500	109,765	111,764	112,764	79,529	113,000	113,500	113,500	117,959
RTO B	(79,500)	(113,500)	(100,499)	(100,499)	(133,499)	(133,499)	(91,500)	(99,739)	(99,739)
RTO C	(22,000)	(56,000)	(56,000)	(28,000)	(37,710)	(37,710)	(37,710)	(29,324)	(52,614)
RTO D	38,000	21,988	21,988	21,988	31,852	13,864	14,364	14,364	28,865
Total	61,000	(37,748)	(22,747)	6,253	(59,828)	(44,345)	(1,345)	(1,198)	(5,529)
Cost / MW Inc Load	12.20	-14.93	-7.51	1.55	-27.12	-16.57	-0.32	-0.29	-1.34

Summary of Iteration Results	3rd Pass - RTO A	3rd Pass - RTO B	3rd Pass - RTO C	3rd Pass - RTO D	4th Pass - RTO A	4th Pass - RTO B	Global LMP
Notes:	RTO A solves 3rd time	RTO B solves 3rd time	RTO C solves 3rd time	RTO D solves 3rd time	RTO A solves 4th time	RTO B solves 4th time	Global LMP Solution
RTO Net Export	**9**	**10**	**11**	**12**	**13**	**14**	**Global**
RTO A	(2,135)	(2,135)	(2,135)	(2,135)	(2,135)	(2,135)	(1,528)
RTO B	2,294	2,294	2,752	2,752	2,752	2,752	1,143
RTO C	1,706	1,706	1,248	1,248	1,248	1,248	1,710
RTO D	(1,865)	(1,865)	(1,865)	(1,865)	(1,865)	(1,865)	(1,325)
Total	0	0	0	0	0	0	0
Incremental Gen & Import	**9**	**10**	**11**	**12**	**13**	**14**	**Global**
RTO A	5,000	5,000	5,000	5,000	5,000	5,000	1,459
RTO B	(2,294)	(2,000)	(2,458)	(2,458)	(2,458)	(2,000)	524
RTO C	(706)	(706)	0	0	0	0	200
RTO D	2,000	2,000	2,000	2,000	2,000	2,000	2,817
Total	4,000	4,294	4,542	4,542	4,542	5,000	5,000
Cost	**9**	**10**	**11**	**12**	**13**	**14**	**Global**
RTO A	113,431	113,431	113,431	113,431	113,431	113,431	(6,449)
RTO B	(99,739)	(91,353)	(104,921)	(104,921)	(104,921)	(91,876)	(17,614)
RTO C	(52,614)	(52,614)	(32,376)	(32,376)	(32,376)	(32,376)	(28,275)
RTO D	28,432	28,432	28,432	28,432	28,432	28,432	56,822
Total	(10,490)	(2,104)	4,566	4,566	4,566	17,611	4,484
Cost / MW Inc Load	-2.62	-0.49	1.01	1.01	1.01	3.52	0.90

Table 4-4 Results of Example Three

Note that in Table 4-4, the Isolated Case is a feasible case with the Incremental Gen & Import values matching the load changes from the base data. When the Incremental Gen & Import values in an iteration do not match the values in the Isolated Case, i.e., 5000, (2000), 0, 2000, and a total of 5000, it is an indication that the iteration has not reached feasibility for all RTOs. That condition is reached only at Iteration 14. In the final column showing the Global LMP Solution, the energy balance equations for each RTO are relaxed. Instead, it is only required to satisfy the total energy balance of 5000 MW at the interconnection level.

Figure 4-14 plots the dispatch cost of each RTO and the total cost of the entire interconnection after each iteration. Notice the total cost curve. It starts from a high value for the Isolated Case, and fluctuates until Iterations 6 to 14 when the process finally converged to a globally feasible and locally optimal solution. Compared to the last data point, which is the Global LMP solution, the cost at the 14th iteration and the cost at the Global LMP solution are reasonably close to each other. The values in the intermediate iterations are not reliable because the solutions were not yet feasible. Note in addition that even though the total cost at the local and the global optima are similar, the costs to each RTOs can be quite different. Thus, it can be seen that there may be many local optimal solutions that vary significantly in terms of regional costs.

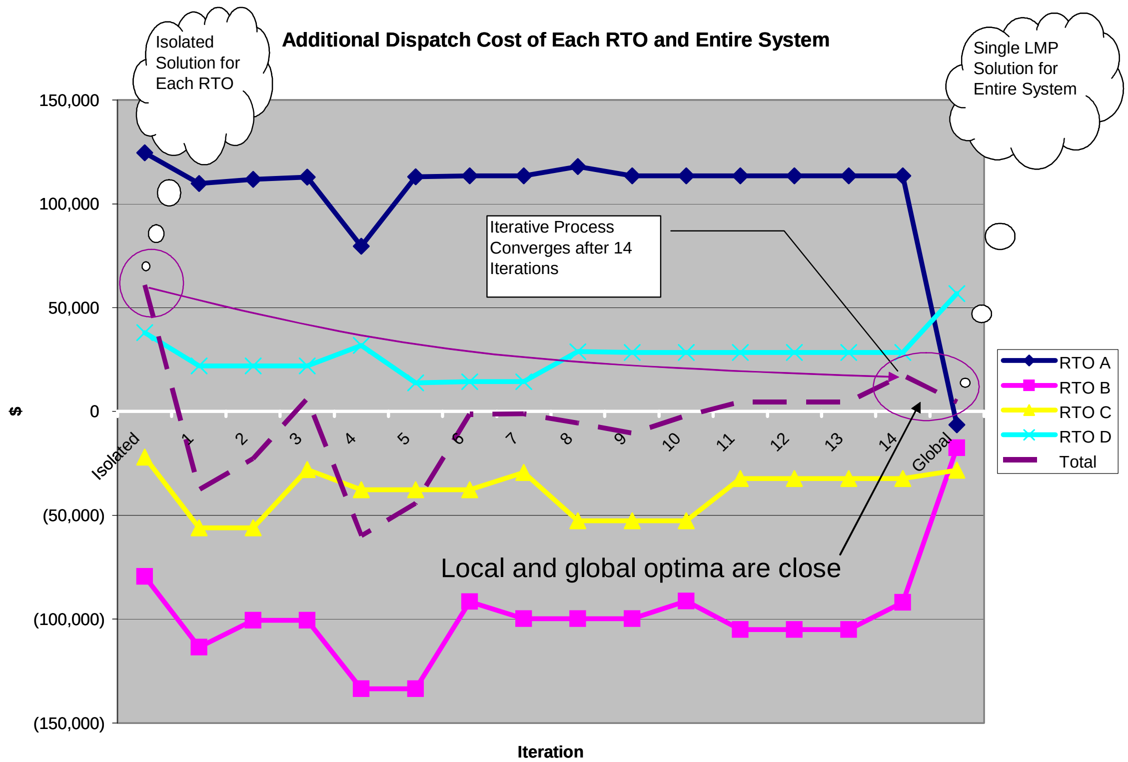

Figure 4-14 Dispatch Costs of Each RTO and Entire System for Each Iteration for Example Three

Figure 4-15 shows the net exports of each RTO through the iterative process and also contrasts the Global solution with the CCMP solutions.

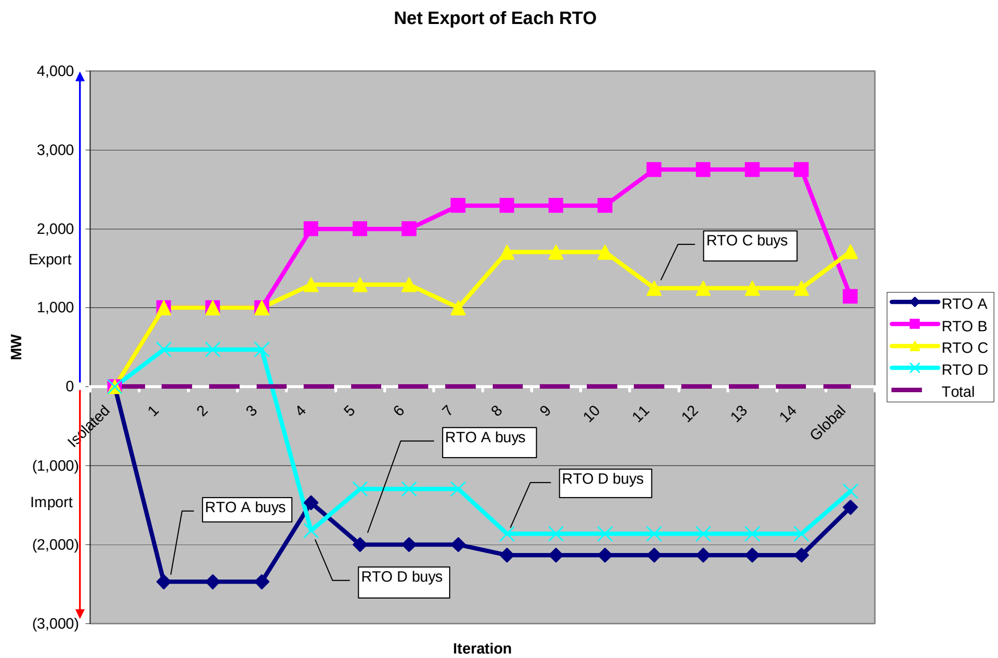

Figure 4-15 Net Export of Each RTO for Each Iteration for Example Three

Figure 4-16 plots the congestion index for each iteration and shows the much higher congestion resulting from the converging solutions and the Global solution as compared to the Isolated Case.

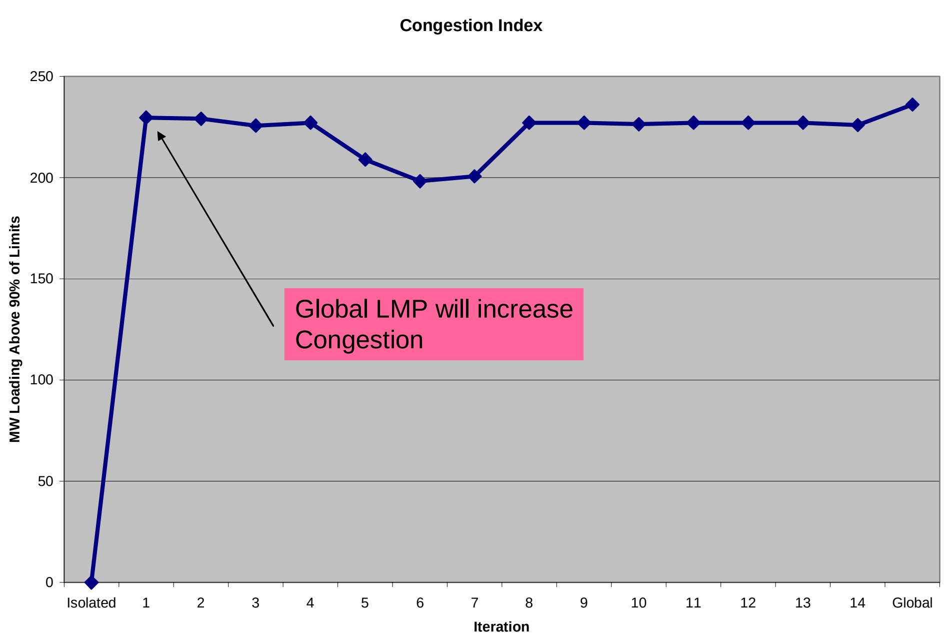

Figure 4-16 Congestion Index for Each Iteration for Example Three

Figure 4-17 plots the line flows on the ten flowgates for each iteration and also the limits of three flowgates.

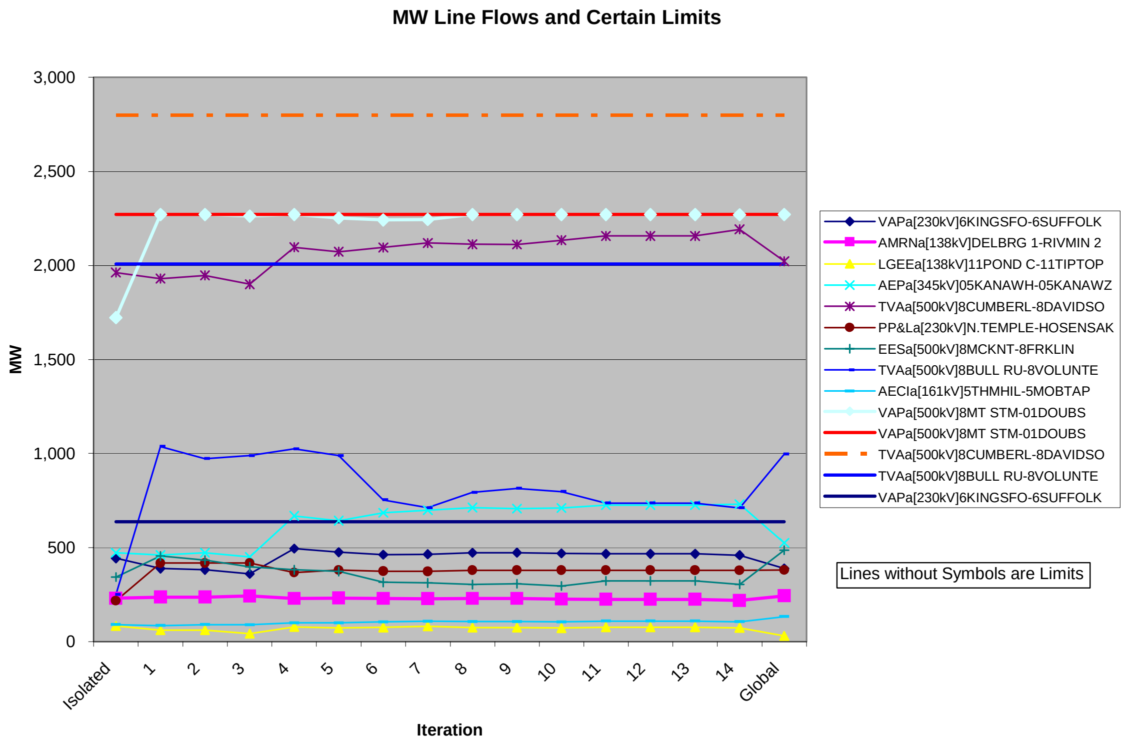

Figure 4-17 Line Flows and Limits for Each Iteration for Example Three

5
FINANCIAL SETTLEMENT

Financial Settlement for Equitable Sharing of Market Savings

The basic objective of LMP over as wide a market area as possible is to achieve maximum market efficiency. This paper has shown that it is plausible to achieve maximum market efficiency without having a single LMP system implemented over an entire interconnection, through the concept of the Virtual RTO and counting on the market to respond to the price signals to achieve the same effect.

Along with greater market efficiency comes the problem of equitable sharing of market benefits to compensate for costs which accompany market liberalization. Regions with inexpensive power plants will likely see some portion of that cheap energy going to other regions where local generation is expensive. The effect of market efficiency, without equitable sharing of that saving, is to increase the cost of electricity in the exporting regions and to lower the cost of electricity in the importing regions. Why would consumers and state regulators want market efficiency if it means that the cost of electricity to them and to their constituents will go up?

In the vertically integrated utility world, such economy interchanges took place regularly and the equity issue was resolved by setting by the transaction price at the middle between the incremental costs of the seller and the buyer, so that both sides come out ahead and share the savings equally. In other words, the ratepayers in the exporting region will see a reduction in their costs and the ratepayers in the importing region will also see a reduction in their costs. With a win-win solution, economy interchanges make practical sense to every party.

With market liberalization, the customers in the importing regions receive the savings and the generating companies which supply the energy receive profits, but the customers in the exporting regions may see their costs go up. The question then is, “Is there a system whereby everyone comes out ahead?”

One answer is to implement a shared savings formula among the RTOs in an interconnection, such that the savings all flow to the customers in each RTO. The generators will still make their profits because their bid prices already include profits. The exact formula can be negotiated among the stakeholders in the entire interconnection. One simple approach is used in this paper for illustration purpose only. That approach is as follows:

1. Perform a reconstruction of each RTO’s dispatch for a given hour with limitations put on the PSEs in that RTO so that they cannot participate in the other RTO power markets, except for firm contracts. In other words, OOMS (out of market sales) are assumed to be unavailable. Then the optimal dispatch for the RTO will see the benefits of the local generation meeting the local demand.

2. Add the costs of all the RTOs reconstructed under step 1.

3. Add the actual costs of all the RTOs, as operated for that hour, to give the total interconnection cost.
4. Subtract the total actual cost in step 3 from the total cost in step 2 to compute the realized cost savings due to interconnected market operation.
5. Take the cost savings in step 4 and prorate it among the RTOs in proportion to their reconstructed costs computed in step 1.
6. Each RTO takes its reconstructed operating cost for the hour in step 1 and subtract from it the prorated cost savings in step 5. The result is the final settled cost for the RTO.
7. The RTOs exchange funds, through accounting, so that each RTO will realize the settled costs at the end of an accounting period.

A conceptual example of this is illustrated in Figure 5-1.

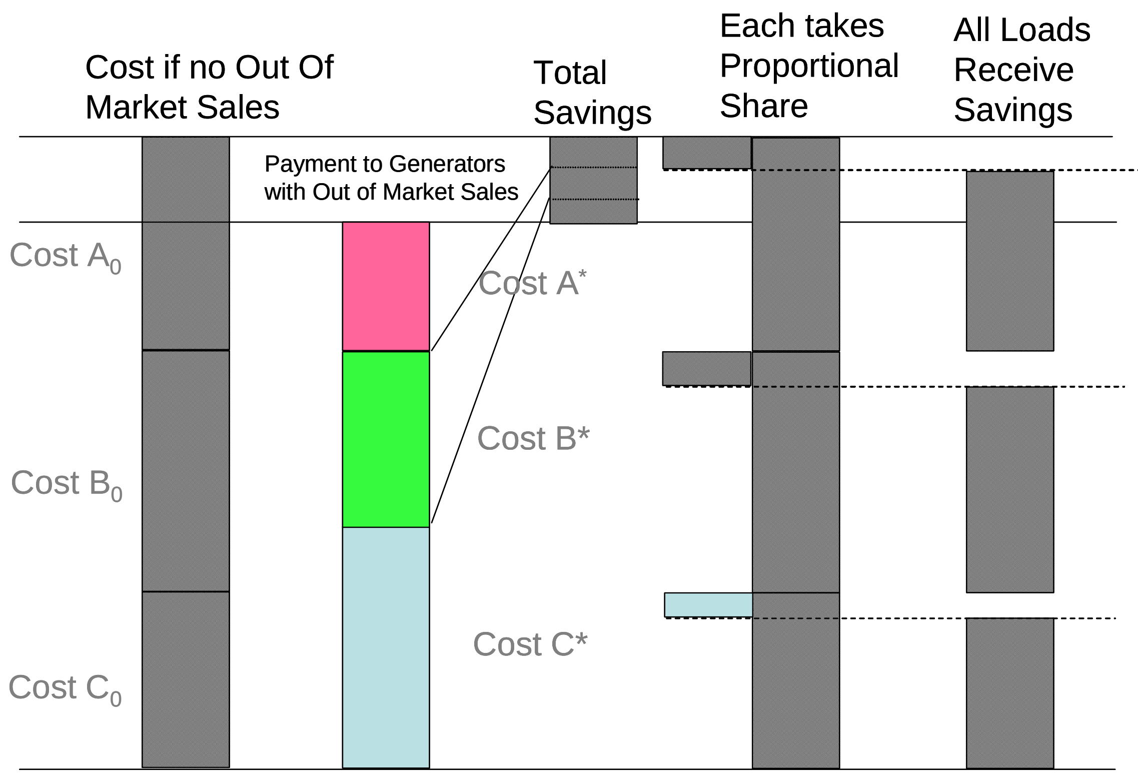

Figure 5-1 Sharing of Market Efficiency Savings among RTOs in an Interconnected Power Market assuming three RTOs, A, B and C.

Table 4-1 provides more details about the shared savings formula.

	System A	System B	System C	Total
Payment to Generators Inside System	Cost A^*	Cost B^*	Cost C^*	Cost S^* =Sum
Cost if Isolated	Cost A_0	Cost B_0	Cost C_0	Cost S_0 =Sum
Savings Received	$(S_0 - S^*) \times A_0 / S_0$	$(S_0 - S^*) \times B_0 / S_0$	$(S_0 - S^*) \times C_0 / S_0$	$(S_0 - S^*)$

Table 5-1 One Formula for Sharing Market Efficiency Savings among RTOs in an Interconnected Power Market assuming three RTOs, A, B and C.

Note that there may be other sharing formulae that would work as well or better. For example, one could use peak load as the basis for sharing. It would be a constant ratio among the RTOs instead of a ratio that changes every hour, as would be the case for the one illustrated in Table 5-1. Other bases for sharing could be population, number of customers, or total generation capacity, etc. What is important in this discussion is that some politically acceptable formula could be agreed upon by all stakeholders in the entire interconnection and the computers can then be trusted to carry out the reconstruction and the settlement of the accounts.

Such reconstruction and settlement systems were successfully used by a number of power pools before deregulation, e.g., PJM, for equitably sharing the benefits of pool operation among the member power companies.

Experiment with Example Two – Reconstruction for Shared Savings

The Example Two used in section 4 of this paper can now be used to illustrate the shared savings concept. Recall that the Base Case was a global LMP solution for the entire interconnection. Therefore, it may be viewed in this exercise as the result of an efficient market operation for the entire power market. In other words, we will use it as the total interconnection cost shown in step 3 in the previous discussion.

The costs for each RTO operated in “isolation” as described in step 1 are the costs for each RTO in Iteration 7 already computed in Example Two. Due to the electrical coupling among the RTOs, the reconstruction of each RTO affects the other RTOs. Therefore, it require the reconstruction to go through the second round of iterations, to reach convergence in the feasibility of the reconstructed solution. That convergence was reached after Iteration 7. For convenience, the summary results of Example Two are repeated in Table 5-2.

Results for Example 2 (Reconstruction for Shared Savings)

Summary of Iteration Results	**Global LMP**	**Solve RTO A**	**Solve RTO B**	**Solve RTO C**	**Solve RTO D**	**Solve RTO A Again**	**Solve RTO B Again**	**Solve RTO C Again**	**Solve RTO D Again**	**Global LMP**
Notes:	Initial solution	RTO A is balanced first.	RTO B is balanced next.	RTO C failed to balance.	RTO D is balanced but RTO C still not balanced.	RTO A is balanced but RTO C still not balanced.	RTO B is balanced but RTO C still not balanced.	RTO C is now balanced.	RTO D's balance is still valid.	Solution is slightly different from initial solution.
RTO Net Export	**Base Case**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
RTO A	(4,473)	(1,998)	(1,998)	(1,932)	(2,450)	(3,179)	(3,179)	(2,932)	(2,932)	(4,502)
RTO B	1,537	1,541	1,991	(4)	0	0	0	860	860	1,588
RTO C	4,951	5,222	5,230	4,101	4,129	4,858	4,858	2,553	2,553	4,914
RTO D	(2,015)	(2,012)	(2,012)	(2,008)	(481)	(481)	(481)	(481)	(481)	(2,000)
Total	(0)	2,754	3,212	157	1,198	1,198	1,198	0	0	0
Cost	**Base Case**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
RTO A	(141,902)	(60,223)	(60,223)	(60,223)	(60,223)	(63,228)	(63,228)	(63,228)	(63,228)	(114,694)
RTO B	(10,188)	(10,188)	2,510	2,510	2,510	2,510	2,500	2,500	2,500	(15,462)
RTO C	(52,502)	(52,502)	(52,502)	(128,890)	(128,890)	(128,890)	(128,890)	(161,754)	(161,754)	(63,466)
RTO D	(99,580)	(99,580)	(99,580)	(99,580)	(70,057)	(70,057)	(70,057)	(70,057)	(70,057)	(110,803)
Total	(304,172)	(222,494)	(209,795)	(286,183)	(256,660)	(259,664)	(259,674)	(292,538)	(292,538)	(304,425)
	Base Case	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
Congestion Index	485	268	260	300	227	234	234	260	260	484
MW Flow	**Base Case**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Global**
VAPa[230kV]6KINGSFO-6SUFFOLK	607	588	584	637	558	545	545	592	592	607
AMRNa[138kV]DELBRG 1-RIVMIN 2	257	260	260	227	230	241	241	230	230	257
LGEEa[138kV]11POND C-11TIPTOP	110	110	110	138	126	114	115	143	143	111
AEPa[345kV]05KANAWH-05KANAWZ	650	696	707	689	607	581	581	661	661	649
TVAa[500kV]8CUMBERL-8DAVIDSO	2,193	2,191	2,199	2,150	2,105	2,071	2,070	2,249	2,249	2,196
PP&La[230kV]N.TEMPLE-HOSENSAK	304	310	308	310	319	319	319	315	315	304
EESa[500kV]8MCKNT-8FRKLIN	769	696	679	758	743	815	815	637	637	765
TVAa[500kV]8BULL RU-8VOLUNTE	2,008	1,602	1,537	1,696	1,619	1,757	1,755	1,590	1,590	2,007
AECIa[161kV]5THMHIL-5MOBTAP	119	126	128	89	90	87	87	106	106	120
VAPa[500kV]8MT STM-01DOUBS	2,271	2,271	2,268	2,271	2,271	2,271	2,271	2,271	2,271	2,271

Table 5-2 Results of Example Two

The results of applying the sharing formula are shown in Table 5-3 below:

Savings Allocation

Total Savings for Entire Interconnection $11,634

	Base Case Load (MW)	Incremental Load Change (MW)	Load Served (MW)	Cost of Base Case Load
RTO A	135,000	-	135,000	$4,300,714
RTO B	165,500	1,000	166,500	$4,561,594
RTO C	120,000	(5,000)	115,000	$3,540,000
RTO D	50,000	(1,000)	49,000	$1,563,889
Total	470,500	(5,000)	465,500	$13,966,197

	Total Reconstructed Cost	% of Total Reconstructed Cost	Allocated Savings	Settled Total Cost
RTO A	$4,237,487	31%	$3,605	$4,233,881
RTO B	$4,564,094	33%	$3,883	$4,560,211
RTO C	$3,378,246	25%	$2,874	$3,375,372
RTO D	$1,493,832	11%	$1,271	$1,492,561
Total	$13,673,659	100%	$11,634	$13,662,025

	Final Cost / MWh	$/MWh Savings	Avg $/MWh for In Market Sources
RTO A	$ 31.36	$ 0.50	31.86
RTO B	$ 27.39	$ 0.17	27.56
RTO C	$ 29.35	$ 0.15	29.50
RTO D	$ 30.46	$ 0.82	31.28

Table 5-3 Results of Allocating Savings to Each RTO

The cost savings to each RTO's customers are shown graphically in Figure 5-2.

Figure 5-2 Effect of Sharing Market Efficiency Savings among RTOs on the Average Electricity Prices to Customers in Example Two

The savings can also be shown in the form of the graphs illustrated in Figure 5-1. The data table associated with Figure 5-3 are found in Table 5-4.

	Actual Cost	Cost if Isolated	Allocated Savings	Settled Cost
RTO A	$4,158,813	$4,237,487	$3,605	$4,233,881
RTO B	$4,551,405	$4,564,094	$3,883	$4,560,211
RTO C	$3,487,498	$3,378,246	$2,874	$3,375,372
RTO D	$1,464,309	$1,493,832	$1,271	$1,492,561
Total	$13,662,025	$13,673,659	$11,634	$13,662,025

Table 5-4 More Results of Allocating Savings to Each RTO

Table 5-4 shows that the savings are allocated in proportion to the "Cost if Isolated" column. While Figure 5-2 shows the effect of these savings on the average prices of electricity, such effects do not seem to correspond with the allocated savings shown in Table 5-4, because the graphs display average prices and not total dollar savings. Figure 5-3 shows the effect in terms of the total dollar savings, and it clearly shows the fairness of the allocation. Because the magnitudes of the total costs are so high, the savings are not visible in the graphs. In order to make the savings visible but retain their proportionality, they were scaled up by a factor of 100 before being plotted in Figure 3.

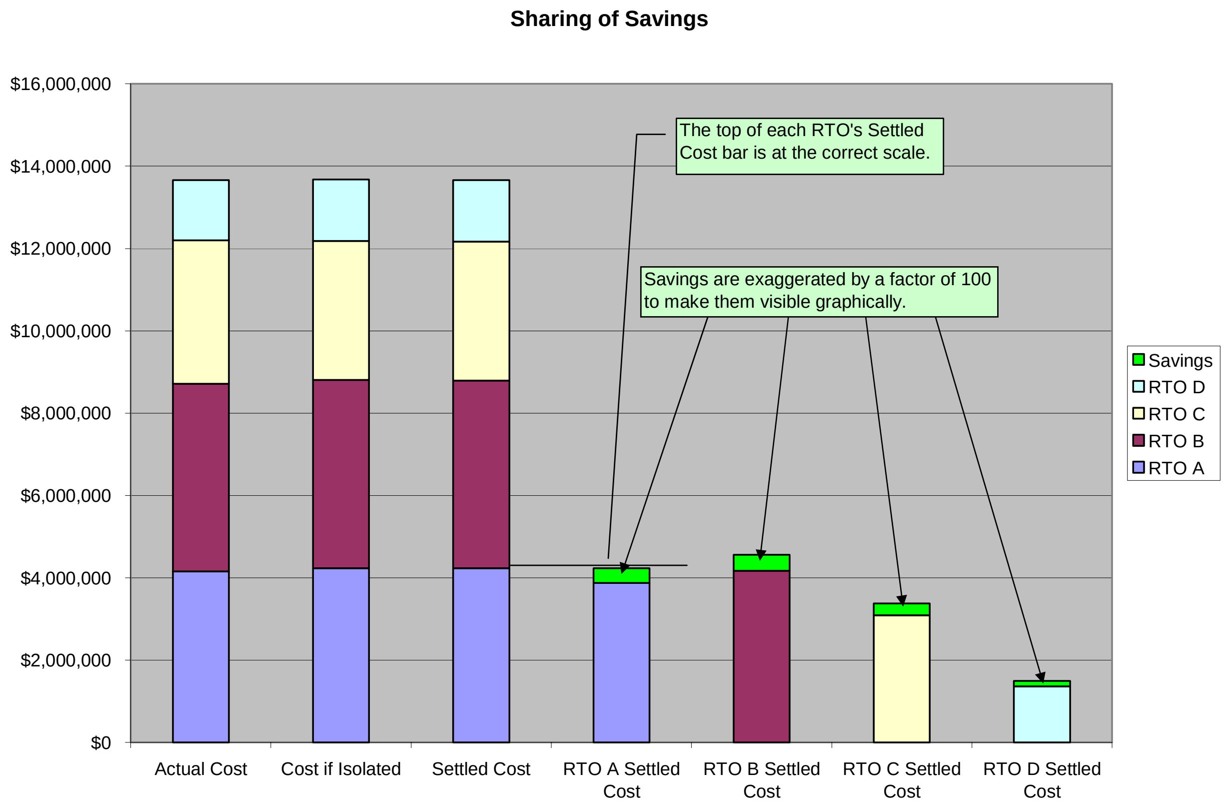

Figure 5-3 Effect of Sharing Market Efficiency Savings among RTOs on the Settled Cost to Customers in Example Two

With Example Two, the concept of using a reconstruction of the “isolated” RTOs for allocating market savings equitable has been illustrated. Computationally, there is no technical difficulty in implementing such a system. In practice, this concept offers an alternative way of meeting both the market efficiency objective and the objective of equitable sharing of the benefits among the different regions in the entire power market.

6
CONCLUSION

This paper has presented some data about the state of transmission congestion in the Eastern Interconnection during the summer of 2002. It calls attention to the need for new transmission investment for relieving the worsening transmission bottlenecks.

This paper has provided some innovative concepts for solving some of the difficult unsolved problems arising from implementing the LMP on an interconnection.

1. Specifically, the inter-RTO congestion management coordination problem is proposed to be solved by the Virtual RTO concept, through the use of three types of glue:
   - Common Power System Model
   - Common Definition of Cohesive Electrical Zones (CEZ)
   - Real-Time Data (network status, dispatch decision, actual measurement data, market price data)
2. A method called the Coordinated Congestion Management Procedure (CCMP) is proposed which is shown in the paper to have good convergence properties. However, in situations where convergence may fail, it is important to have an online reliability backstop system, like the IDC.
3. E-tags can evolve to the next stage when they represent both the current point-to-point transactions and the proposed portfolio tags created by each LMP-based RTO from its solution from its SCD software, aggregated in the granularity of the CEZs.
4. The CCMP will work together with the competitive power market through the human loop together with the Virtual RTO implementation to achieve global market equilibrium. Rules need to be clarified in the SMD with respect to out of market sales, which is the means for achieving maximum market efficiency for the entire interconnection.
5. A more direct approach using the RTOs and automation to iterate towards the global market optimal LMP solution was also proposed. An example demonstrated convergence to a local optimal solution reasonably close to the global optimum.
6. A method for equitable sharing of market savings due to the out of market sales for an interconnection is proposed. This ensures that customers in all regions benefit equitably from having effectively a single power market. It is a win-win solution for all parties.

These new concepts were demonstrated where possible in this paper by illustrative examples.

In conclusion, it is hoped that these ideas will be discussed by stakeholders in the electric power industry so that they may contribute to the solution of these difficult problems.

7
REFERENCES

1. “Summary Report - Summer 2002 Eastern Interconnection Pre-Season Study and New Tools for Community Activity Room”, EPRI Report, June 2002.
2. Lee, Stephen T., “Community Activity Room as a New Tool for Transmission Operation and Planning Under A Competitive Power Market,” EPRI internal paper, September 2002.

A
New Operating Tools (Community Activity Room)

TagNet Display and Community Activity Room

EPRI, in cooperation with NERC, is testing a pilot display on the TagNet, called the Community Activity Room, to provide a directly useful tool for operators in an on-line environment for the Eastern Interconnection. As an extension to the NERC/EPRI TagNet Display, it is available to Reliability Coordinators through a menu from the NERC Reliability Coordinators Information System. It combines the hourly analysis by TagNet of all the E-tags in the Eastern Interconnection which are aggregated into net schedules between different sub-regions (or bubbles) and displayed as bubble diagrams. One of the bubble diagrams treats the Eastern Interconnection as four quadrants. The net export values of the four quadrants determine the current hour's operating point for the Eastern Interconnection. It is plotted as a color-coded disc on a two-dimensional floor plan of the Community Activity Room. Operators can look at this web-page once every hour to check whether the color disc is blue, orange or red. If it is orange or red, it means that the current operating point may violate some post-contingency overload or voltage limits. In that situation where the color disc is inside the Community Activity Room, the web-page shows the closest constraint, and how far it is away from the color disc. It also shows the list of potential contingency-constraint pairs, sorted in order to potential percentage limit violations. When the color disc is orange or red, and lies outside the Community Activity Room, the picture shows an initial estimate of where the current operating point should be to get back inside the room. The tabular display provides the list of potential contingency-constraint pairs, sorted in decreasing order of percentage limit violations.

Because of the complexities and the size of the Eastern Interconnection, the Community Activity Room is dependent on the network load and generation pattern. From the 32 runs made during the study, the run that matches best with the current operating point is automatically selected by the CAR Painter program. Matching is ranked according to the sum of the absolute magnitudes of the differences between the net exports of the current operating point and the net exports of the 32 runs. The constraints derived from the 32 runs are adjusted by the current hour's load levels, estimated by a combination of typical hourly weekday or weekend load profile and estimated daily peak loads for certain control areas.

An example display of the Community Activity Room is shown in Figure A.1.

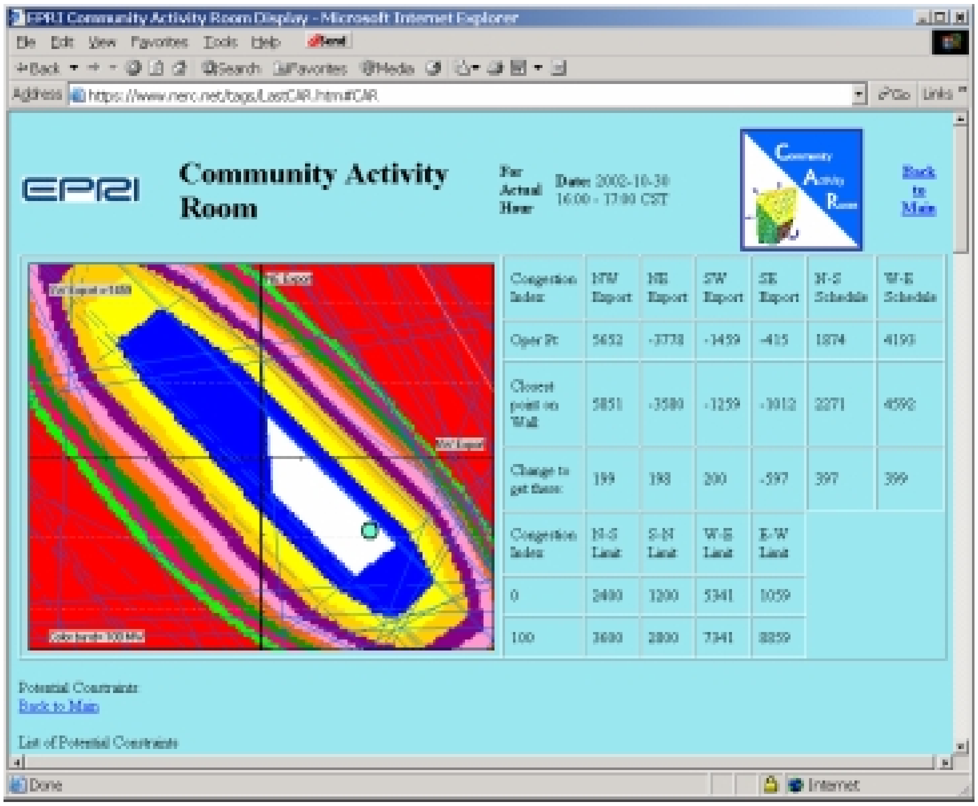

Figure A.1 Sample Display of the On-line Community Activity Room

On the left side of the web page is the painting from the CAR Painter, for the current hour's net export out of the SW quadrant, which is indicated by the text label on the upper left corner of the painting. The current operating point (or the floating light bulb) is shown by the blue disc. It lies outside the white zone, in the blue area, which represents a potential total post-contingency overloads of 1 color band, which is shown in the text label as 100 MW each. In other words, it is between 1 and 100 MW. The white zone represents zero potential post-contingency overloads. Note also that there were a few voltage limit constraints represented in the data and they contribute to the overload indices displayed by the CAR Painter, at the equivalent rate of 10 MW overloads for 1 kV of voltage drop below the lower voltage limit.

The color code of the current operating point assigns the blue color if it lies in the white or the blue zone. If it lies in the yellow zone, the disc becomes orange. If it lies in the orange zone and beyond, the disc becomes red. A small light-blue dot is shown in the painting when the current operating point is outside the white zone. The location of the light-blue dot is an initial estimate by the CAR Painter of the closest point inside the Community Activity Room. It is not exact because the CAR Painter is not an optimization program. However, it gives the operator a good indication on how far it is away from the current operating point. The exact coordinates of the current operating point, the best point inside, and the changes to get there are shown in the table on the right side of the web page. These numbers show the net exports of the four quadrants as well as the N-S and W-E schedules.

In most situations, the current operating point lies in the white zone, and CAR Painter will show a short black line segment which marks the closest point to the nearest wall from the current operating point. That indicates the point (in three dimensional coordinates) of the spot on the wall (imagine it as a three-dimensional physical wall) which represents that closest constraint. That closest wall is also represented by the separation between the blue and the white zones in the general direction of the short black line segment. In some situations, the short black line may not lie exactly on the boundary between the white and blue zones, even though it is on the wall itself. The reason is that where it lies on the wall is not on the same floor level which is painted. Because the wall may be tilted at an angle to the floor, the point on the wall which is closest to the current operating point (which lies on the current floor level) may be above or below the floor level.

Again, the exact coordinates of the current operating point, the closest point on the wall, and the changes to get there are shown in the tabular display.

In the upper-left corner of the tabular display is the current Congestion Index. (The zero value is not shown in Figure A.1.) Also shown is the estimated maximum transfer limits in the directions of North to South, South to North, West to East, and East to West, for two Congestion levels, zero and 100. For example, Figure A.1 shows that the maximum N-S limit is 2400 MW, and that if one accepts the Congestion level of 100, the maximum N-S limit would increase to 3600 MW.

Below the CAR painting, not shown in Figure A.1, is a tabular display listing the potential constraints applicable to the current operating point. The control areas which own the constrained facilities are listed. At the rightmost column are the estimated load levels at the current hour, expressed as a percentage of the Summer 2002 peak load for the corresponding control area. The assumed MW or voltage limits are also shown, so that if the current limit is different, the operator can make a mental or simple mathematical adjustment for it.

CAR Painter Program

The CAR Painter program is available to the Reliability Coordinators, the PSAST members and to EPRI members. The special version of the CAR Painter program available only the Reliability Coordinators include the ability to download the current operating point from the TagNet web site. This will enable them to make current hour analysis of those constraints of special interest to them.

The main capabilities of the CAR Painter program are summarized in the bullets below.

- For the version available only to the Reliability Coordinators, after downloading the current operating point from the TagNet web site, it automatically finds the case from the set of study cases that best matches the current operating point. If the user also download the confidential SDX files on the computer, the CAR Painter will use the current day's peak load forecast from a number of control areas to adjust the Peak Load factor for adjusting the constraints. Hourly profiles for the weekday and for the weekend day can be specified also.

- For the planning version available to the PSAST members, the operating point may be entered manually, and a case may be selected by the user among all the study cases. A uniform Peak Load Adjustment % may be entered manually to adjust the effect of the current load on the constraints.

- Constraints from all the transfer scenarios of the selected case may be all chosen to be plotted, or a particular transfer scenario may be chosen.

- Constraints from all control areas may be chosen to be plotted, or those from a single control area may be chosen.

- Redundant constraints may be excluded or included.

- Lines representing the constraints may be plotted on top of the color bands. If they are plotted, the user can click on a constraint line to see information about the constraint, e.g., the constraint number, the constraint name, the contingency, the control area associated with the constraint, the voltage class, and the limit.

- The current operating point may be manually entered in the Assess window, and upon return to the main window, the user can Paint the Community Activity Room and see the location of the current operating point in the painting itself. The CAR Painter will indicate the closest constraint, if the operating point is inside the white zone. It will indicate the best and closest point inside the white zone, if the operating point is outside it. By using the Change Operating Point button in the Assess window, the user can move the current operating point to either the closest point on the wall or the best point inside, whichever case applies.

- There is a simplistic animation feature whereby the CAR Painter steps through the SW Export from –5,000 MW to 5,000 MW in 1000 MW steps.

- The painting can be copied to the Windows clipboard or saved as a bmp file.

- The step size of each color band may be selected from 100 MW to 2000 MW.

- The equivalence factor that translates 1 kV of voltage violation to MW of overloads can be changed by the user from the default value of 1kV = 10 MW. This can be used to see the sensitivity of the voltage constraints on the color bands.

The CAR Painter program is a proprietary copyrighted software of EPRI. For questions, please refer to Stephen Lee at slee@epri.com

Community Activity Room (CAR)™ - A Visualization of Interstate Wholesale Electric Power Market Congestion

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Introduction

The power market can be viewed as a community of electricity participants involved in power transactions affecting one another. These participants -- generators, transmission owners, grid operators, traders, load-serving entities, and ultimately the customers – will be able to plan their activities more efficiently if they know how transmission limitations will affect them. A newly developed software technology for power trading, Community Activity Room (CAR), uses the metaphor of a many-sided room to show the ranges of operation within which market activities can freely take place. CAR graphics define the limits of the power market, locating congested bottlenecks and suggesting the combinations of net import and net export from various control areas that will avoid congestion. The Community Activity Room concept also brings transmission planning and operation to the next generation of probabilistic power system reliability assessment and promotes integration of reliability and market efficiency.

CAR Technology

With the new restructured environment where complex transmission bottlenecks are limiting the efficiency and reliability of emerging power markets, the concept of the Community Activity Room was developed by the author during a planning study of the interregional transmission transfer capacities of the Eastern Interconnection of North America, in response to the need to provide maximum information from a limited number of computer cases, and where complex results had to be visualized.

The CAR technology takes a large set of high dimensional transmission constraints, based on a list of potential transmission outages, and reduces them to a visual, three-dimensional set of equations, akin to walls of a room. Only potentially binding transmission bottlenecks are graphically painted in color, showing increasing degrees of congestion as market activities increase. The interior region of this image-- where there is no potential congestion-- is the Community Activity Room. This is the area in which wholesale power transactions can freely take place without running into the transmission walls. The current state of the power market is represented by a floating point of light (light-bulb) inside the CAR. Operators monitor the location of the light-bulb and are warned when it comes close to a wall. The CAR will warn the operators how far it is from the walls, and which wall is closest to it. When the market moves the light-bulb beyond the walls, the CAR will show the shortest way to get back inside. This may be achieved by market mechanisms or reliability procedures, or both.

™ The Community Activity Room (CAR) is a trademark of EPRI.

The size of the room available for inter-state power transactions depend on the amount of local loads that also use the same transmission lines. This is much like local traffic using inter-state highways for local trips and causing congestion during rush hours. The equations for the CAR account for these effects and also adjust for the effects of generation patterns, before the detailed equations are aggregated into three dimensions.

There are two types of walls – hard walls and soft walls. Hard walls represent the boundary of operation beyond which a transmission facility will be continuously overloaded, or instability will occur. Soft walls represent the potential boundary of unsatisfactory operation if a particular transmission outage contingency happens. They represent a buffer zone wherein if a particular outage happens, there is no immediate overload and the operator will then move the operating point closer to the center of the room. When an outage happens, a new set of walls will be computed immediately so that the operator knows the new set of hard and soft walls.

Figure 1 shows an example of a 3-D Community Activity Room for a system with four interconnected regions.

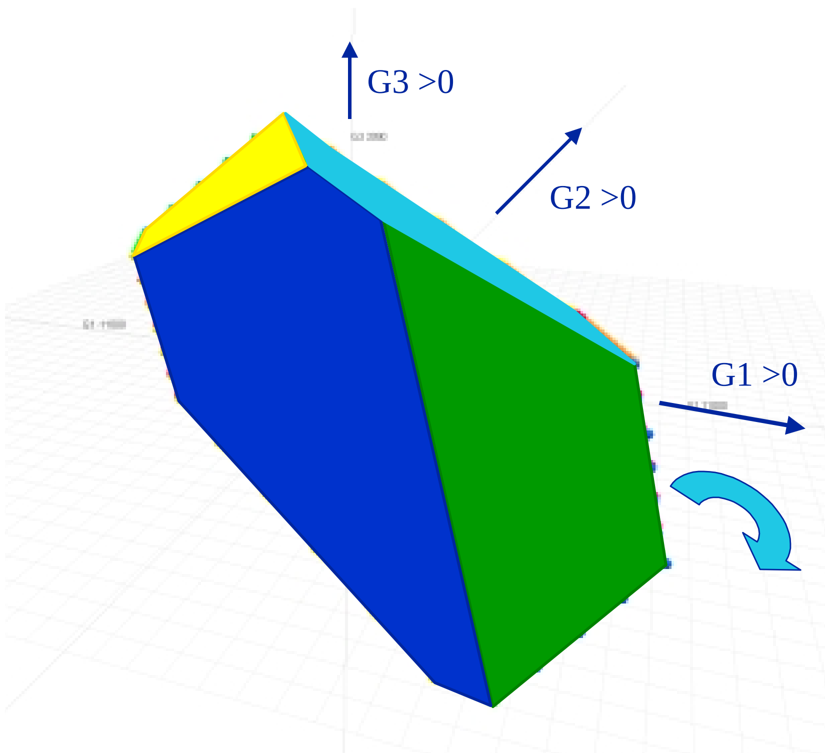

Figure 1 – Example of a 3-D Community Activity Room
(G1, G2 and G3 are net exports from region 1, 2 and 3, for a 4-region system)

An example of a two-dimensional visualization is shown in Figure 2. The horizontal axis represents net export out of the NW region, and the vertical axis represents net export out of the NE region. The SW net export is zero for all points in Figure 2. The system shown in Figure 2 consists of four regions connected to one another only. Therefore, the SE region's net export can be determined from the net exports of the NW, NE and SW regions by SE Export = – NW Export – NE Export – SW Export.

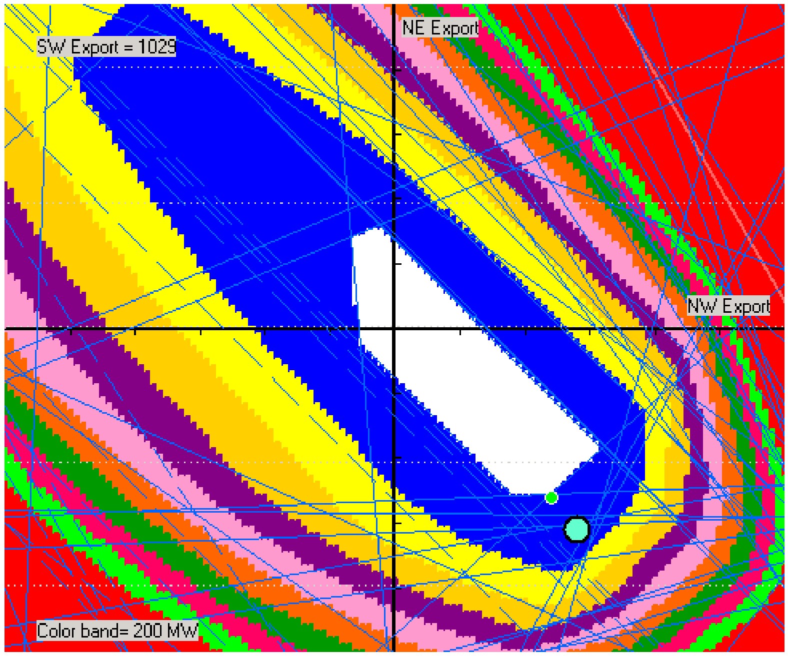

Figure 2 – Community Activity Room Painted as Potential Overload Levels Shown in Color Bands of 200 MW Steps, with SW Export = 1029 MW

The white zone in Figure 2 shows the operating space within which no constraint is violated, i.e., no potential overloads due to contingencies would occur. The blue zone shows where up to 200 MW of potential overloads may happen, if the system operates in that zone. The yellow zone shows the state space where between 200 to 400 MW of potential overloads may occur, and so on, with 200 MW being the step size of each color band.

The larger blue dot in the blue zone of the chart marks the current operating point of the system, or the light-bulb, with a positive NW export and a negative NW export. Because the light-bulb lies outside of the white zone, the CAR tells the operator the shortest distance and direction to move back inside. The small green dot marks the location. This information will be valuable in an emergency situation of heavy congestion for the most efficient way to relieve congestion.

Under normal condition, the large blue dot is inside the white zone. In that case, a black line segment will be shown marking the location of the point on the closest wall (constraint) as projected onto this plane. Such information is valuable for operators to know, for it warns them about the nearness and location of the transmission bottleneck .

Proven Technology

The foundation technology behind the CAR is proven. The mathematical basis of the CAR is sound. The technology is a creative application of transmission transfer capacity studies to the operating arena. The equations are based on linearization around a full AC power flow model. It is as accurate as the data used in computing the walls. For example, for online applications, the availability status of transmission lines and generators can be modeled by the power flow equations from which the walls would be derived.

Personal computers can be used to continuously derive the equations for the walls, based on a large set of possible operating conditions. These walls can be saved for ready retrieval when new operating conditions are matched against the database. This approach to online reliability assessment will change a number of energy control center applications. Pattern recognition would be applied to quickly assess the current operating point and match it with previously studied cases. At the same time, the computer will derive a new set of equations for the walls that are most accurate for the current operating point, thus adding to the knowledge base.

Innovation

The CAR technology is ingenious in the way many ideas and applications fit together as neatly as a hand in a glove. In the first place, this technology reduces the complex high dimensional transmission constraints into lower dimensions with easily understandable implications for the market.

Secondly, the addition of color-coded probabilities of outages converts today's deterministic transmission reliability criteria into probabilistic criteria of the future. When that is put into practice, it could engender new market products for risk management or insurance against blackouts. EPRI has a plan to use the CAR technology to develop an online probabilistic reliability monitor.

The CAR has linked transmission planning and operation into a unified framework, whereby statistics on congestion and bottlenecks can be communicated to all stakeholders interested in expanding the size of the Community Activity Room, within which the power market will achieve greater efficiency.

Making continuous use of computer power to increase the knowledge base of power market operation, the CAR will take traditional energy management systems from a single-point analysis of the current operating point (the position of the light-bulb) to the next generation where the full range of state space around the current operating point will be presented to the operators. This can be compared to an air traffic radar system that shows all planes on the same screen instead of a warning system which only gives the air traffic controller a yes or no answer about whether an aircraft is within a fixed radius from another one.

The same tool, based on the same data, can be used by grid operators, market participants and transmission owners to view the state of congestion in the market. This assures consistency and same-time access to all market participants.

The CAR has the potential to display market prices in the same way as congestion is displayed. The CAR also has the potential to serve as a real-time toll collection system for transmission usage because the loading of transmission lines of interest can be monitored and analytically attributed to portfolios of market activities. This system, which can complement any power market design, could provide a much needed way to increase the financial incentives for investing in new transmission lines by assuring an attractive but fair return to investors. The tolls would vary, depending on the degree of congestion.

Commercial Feasibility

The CAR prototype was developed in less than three months, a timeframe that gives us a high degree of confidence that this promising technology can be brought to market quickly. Commercialization depends only on the availability of data and the supporting computer and communication infrastructure, both of which are available in many power systems.

Megawatt transfer limits and voltage drop constraints can now be handled by the system; and future work will address voltage stability and dynamic stability in the same framework. Current technology is limited to separate assessments of voltage stability and dynamic stability for a single operating point. The CAR provides a framework for displaying all three types of constraints at the same time.

Uniquely Designed

In North America, wholesale power transactions are electronically tagged from the starting point to the ending point. This system is the North American Electric Reliability Council (NERC) E-tags. EPRI and NERC provide to authorized Reliability Coordinators an online web-based display of power market transactions in bubble diagrams, called the TagNet display. These data enable the current location of the floating light bulb to be calculated. It is used as the input to the display of the Community Activity Room, on the same web-site, through highly colorful CAR paintings

In addition to viewing the CAR on the special web-site, authorized users can download the current location of the floating light-bulb and do detailed analysis with the CAR Painter program.

As a monitoring device of the transmission grid's state of health, the online system accumulates statistics on wholesale power market schedules, congestion indices and limiting bottlenecks. These data are useful input for transmission planning.

Conclusion

The Community Activity Room provides a visual display of electricity market activity in action in a manner analogous to air traffic control systems. It has large commercial potential for transmission pricing and grid stability, as well as risk management and insurance products. More importantly, it offers tremendous potential to launch the electric power industry into the next era of highly efficient power markets worldwide.

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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